[redacted] RF

Idaho National Engineering Laboratory

DOE/GRI Industry Meeting March 4-5, 1986, Review of Geopressured-Geothermal and Co-Production Research

EG&G Idaho

Work performed under DOE Contract No. DE-AC07-76ID01570

DISCLAIMER

DISCLAIMER

January 16, 1987

TO: ATTENDEES OF THE DOE/GRI INDUSTRY MEETING OF MARCH 4-5, 1986 TO REVIEW GEOPRESSURED-GEOTHERMAL AND CO-PRODUCTION RESEARCH

Attached are minutes of the DOE/GRI/Industry meeting. They include a transcript of the questions and answers following each presentation and copies of slides and/or summaries prepared by each of the speakers.

To reduce costs and time required for preparation of the minutes, we have eliminated the verbatim reproduction of the talks. The Appendixes include the slides and graphs used by the speakers and are presented in order of appearance in the DOE and GRI programs which follow.

We believe joint meetings of DOE and GRI with Industry result in excellent information exchange. We appreciate the extra work of the speakers and the interest of the participants.

Sincerely,

H. F. Coffer

H.F. Coffer
EG&G Idaho, Inc.

R. W. Howell

R.W. Howell
Eaton Operating Co., Inc.

HFC/RWH/ls

Attachment

TABLE OF CONTENTS

IV. H. APPENDIX 8

EPRI EXPERIMENT STATUS INCLUDING DISCUSSION AND DIAGRAMS - E. HUGHES/EPRI

I. APPENDIX 9

PLEASANT BAYOU GEOLOGY. COMPLETE WRITINGS INCLUDING CROSS SECTIONS - M. LIGHT/BEG

J. APPENDIX 10

SURFACE WATER QUALITY. INCLUDES WORK DONE AT PLEASANT BAYOU AND GLADYS McCALL AS WELL AS A SHORT SUMMARY - M.A. SALEH/SOUTHERN LOUISIANA UNIVERSITY

K. APPENDIX 11

ANALYSIS OF HYDROCARBONS FROM DOE WELLS. COMPLETE WRITE-UP OF WORK - D. KEELEY/USWL

L. APPENDIX 12

LOG ANALYSIS IN GEOPRESSURED WELLS. ESTIMATION OF MUD FILTRATE RESISTIVITY - M. DORFMAN/UTA

M. APPENDIX 13

COMPACTION OF GULF COAST SHALE AND SANDSTONES SUMMARY AND DISCUSSION - K. GRAY/UTA

N. APPENDIX 14

REVIEW OF GRI PROGRAMS - L. ROGERS/GRI

O. APPENDIX 15

UT/BEG PROSPECT EVALUATION FOR CO-PRODUCTION - M. LIGHT/BEG

P. APPENDIX 16

LSU/GEOLOGIC SURVEY PROSPECT EVALUATION FOR CO-PRODUCTION. INCLUDES TECHNICAL SPE PAPER - Z. BESSOUNI/LSU

IV. Q. APPENDIX 17

N.E. HITCHCOCK SHALE STUDY - K. PETERSON/EOC

R. APPENDIX 18

FIELD TEST RESULTS FROM N.E. HITCHCOCK WELLS
- P. RANDOLPH - IGT

S. APPENDIX 19

MODELING RESULTS FOR N.E. HITCHCOCK
- K. ANCELL/DFA

T. APPENDIX 20

SUMMARY OF SCALE AND ADVERSE CHEMICAL REACTION
RESEARCH - M. TOMSON/RICE UNIVERSITY

I. AGENDA FOR DOE AND GRI MEETING

GEOPRESSURED INDUSTRY FORUM

TENTATIVE AGENDA

	MORNING SESSION MARCH 4, 1986	8:30 - Noon
15 MIN.	WELCOME AND INTRODUCTIONS	H. F. COFFER, EG&G
10 MIN.	PROGRAM OVERVIEW	RAY FORTUNA, DOE-HQ
10 MIN.	FIELD ACTIVITIES SUMMARY	S. PRESTWICH, DOE-ID
10 MIN.	RESEARCH ACTIVITIES SUMMARY	S. PRESTWICH, DOE-ID
30 MIN.	GLADYS McCALL WELL STATUS	T. MEAHL, EOC
45 MIN.	GLADYS McCALL SCALE INHIBITION	M. TOMSON, RICE UNIV.
20 MIN.	BREAK	
30 MIN.	GLADYS McCALL WELL INSTRUMENTATION & MEASUREMENTS	P. RANDOLPH, IGT
30 MIN.	GLADYS McCALL RESERVOIR GEOLOGY REVIEW	C. GROAT, LSU

	AFTERNOON SESSION MARCH 4, 1986	1:30 - 5:00
40 MIN.	GLADYS McCALL RESERVOIR ANALYSIS	D. RINEY, S-CUBED
20 MIN.	PLEASANT BAYOU REWORK	T. MEAHL, EOC
20 MIN.	BREAK	
30 MIN.	EPRI EXPERIMENT STATUS	E. HUGHES, EPRI
30 MIN.	PLEASANT BAYOU GEOLOGY REVIEW	M. LIGHT, BEG
20 MIN.	ENVIRONMENTAL MONITORING: DOE GEOPRESSURED-GEOTHERMAL FIELD ACTIVITIES	V. VAN SICKLE, LSU
20 MIN.	SURFACE WATER QUALITY AT DOE GEOPRESSURED WELLS	F. SALEH, SLU

GEOPRESSURED INDUSTRY FORUM

TENTATIVE AGENDA

	MORNING SESSION MARCH 5, 1986	8:30 - Noon
40 MIN.	ANALYSIS OF LIGHT HYDROCARBONS FROM DOE WELLS	D. KEELEY, USWL
30 MIN.	ANALYSIS OF HEAVY HYDROCARBONS FROM DOE WELLS	O. WERES
40 MIN.	LOG ANALYSIS IN GEOPRESSURED WELLS	M. DORFMAN, UTA
20 MIN.	BREAK	
30 MIN.	LOG DETERMINATION OF SALINITY IN GEOPRESSURED WELLS	H. DUNLAP, UTA
30 MIN.	RESPONSE OF GEOPRESSURED SHALES TO PRODUCTION CONDITIONS	K. GRAY, UTA
30 MIN.	REVIEW OF GRI PROGRAMS	L. ROGERS, GRI
	AFTERNOON SESSION MARCH 5, 1986	1:30 - 5:00
	GAS RESEARCH INSTITUTE PAPERS ON CO-PRODUCTION RESEARCH	

WEDNESDAY, MARCH 5, 1986

AGENDA

GAS RESEARCH INSTITUTE CO-PRODUCTION OF GAS & WATER PROGRAM

(TO BEGIN FOLLOWING MORNING PAPERS FOR DOE PROGRAM)

30 MIN.	OVERVIEW OF GRI CO-PRODUCTION PROGRAM	L. ROGERS, GRI
45 MIN.	UT/BEG PROSPECT EVALUATION, LOGGING RESEARCH AND HYDROCARBON SOURCE ANALYSIS FOR N.E. HITCHCOCK	M. LIGHT, BEG H. DUNLAP, UT
	LUNCH	
45 MIN.	LOUISIANA STATE UNIVERSITY/GEOLOGIC SURVEY PROSPECT EVALUATION AND PROJECT INITIATIONS WITH OPERATORS IN LOUISIANA	Z. BOUSSOUNI, LSU
45 MIN.	EATON OPERATING COMPANY PROSPECT EVALUATION AND STATUS OF N.E. HITCHCOCK AND PORT ARTHUR PROJECTS	B. HOWELL, EOC L. ANDERSON, W. PARISI, AND K. PETERSON, EOC
20 MIN.	BREAK	
45 MIN.	FIELD TEST RESULTS FROM N.E. HITCHCOCK	P. RANDOLPH, IGT
45 MIN.	MODELING RESULTS FOR N.E. HITCHCOCK	K. ANCELL, DF&A
30 MIN.	SUMMARY OF SCALE AND ADVERSE CHEMICAL REACTION RESEARCH	M. TOMSON, RICE

II. TRANSCRIPT OF QUESTION AND ANSWER SESSION

GEOPRESSURED INDUSTRY FORUM

MARCH 4 & 5, 1986

MORNING SESSION, MARCH 4, 1986, 8:30 - NOON

PROGRAM AND ATTENDEES LIST FOLLOW THESE MINUTES

WELCOME AND INTRODUCTION H. F. Coffer, EG&G

PROGRAM OVERVIEW Ray Fortuna, DOE-Washington

Ray Fortuna, the new Program Manager for DOE from Washington, was introduced and asked to make a few comments.

No Questions.

FIELD ACTIVITIES SUMMARY S. Prestwich, DOE-ID

Question (Frank O'Brien, WKT): Susan, in light of the budget problem, and in light of the fact that it has already been a two-year delay in doing the EPRI experiment, why hasn't the decision been made to do it at Gladys McCall?

Comment (Dave Lombard, DOE-HQ): Well, it's flowing doesn't require extensive work.

Question (Frank O'Brien, WKT): I can't understand why that decision and emphasis continues to go to Pleasant Bayou.

Hank rephrases question: Why isn't the decision for EPRI to use the Gladys McCall rather than the Pleasant Bayou well?

Comment (Susan Prestwich, DOE-ID): We looked at that issue and, for several reasons, we chose to continue at Pleasant Bayou. First of all, Pleasant Bayou is a second operating site. It really boiled down to financial aspects. To put that system into McCall we were looking at extensive amounts of dollars. So we have chosen to continue at Pleasant Bayou.

Question (Frank O'Brien, WKT): It's cheaper to do it at Pleasant Bayou than at Gladys McCall? Is that the synopsis of what you're saying?

Comment (Susan Prestwich, DOE-ID): No, I would not say it's cheaper, but I would say at this point it appeared to be a little more cost effective to stay at Pleasant Bayou.

Question (Frank O'Brien, WKT): That remains your decision in light of the budget problem you described?

Answer (Susan Prestwich, DOE-ID): Yes.

Comment (Dave Lombard, DOE-HQ): There are a couple of other factors involved. One of them, of course, is EPRI's objectives. We have consulted very closely with EPRI on this question. They have had a strong preference for Pleasant Bayou. There are a number of reasons that Evan may want to comment on. Secondly, there are some reservoir questions. Our basic objective in the program is to learn as much as we can about what makes these reservoirs flow. At Gladys McCall, we're at the point we're able to run that valve wide open and no matter who makes the prediction, we're going to draw the well down. Some people think it will take a little longer and some people think we'll have it done in a few months, to the point where we'll have accomplished our mission at that site. Right now it is flowing a little over 30,000 barrels a day, and the wellhead pressure at that flow rate, correct me if I'm wrong, is just a little over 1,200 pounds per square inch. You need 1,200 to operate all that surface equipment to separate gas and brine. What's declining is the flow rate. Depending on who does the analysis, sometime this fiscal year or sometime this calendar year, or perhaps sometime next year, we will be at the point where we'll be down to a few thousand barrels a day, and we've learned everything the wellhead can teach us and we'll stop flowing. With that kind of future for the McCall site, and since you're not going to start the EPRI experiment probably until next fall at the earliest, we wondered about our ability to supply fluid and accomplish both objectives of the program at the same time. We don't have quite so many problems with Pleasant Bayou because it hasn't flowed nearly as many barrels. The reservoir is at least as big, and we're not going to start flowing it until we get finished with Gladys McCall. Those are some additional reasons for Pleasant Bayou.

Comment (Evan Hughes, EPRI): Last fall, EPRI did begin to look into moving some experiments to the Gladys Mccall site, and it looked like it wouldn't improve the schedule very much at the time although there have been subsequently more delays at Pleasant Bayou as you've heard this morning. But also we already have Houston Lighting and Power involved at the Pleasant Bayou site, and we didn't find (last fall) comparable utility involvement at the Gladys McCall site, and then the contractor's estimate for installation again was pretty high at the Gladys Mccall site. Those are basically the reasons why we decided that despite the delay in schedule, we better stick to the plan to go to Pleasant Bayou.

Question (D. Bohanan): Evan, if you don't mind me asking, what was the difference between the price paid for electricity at the two sites?

Answer (Evan Hughes, EPRI): It turned out the voided costs are probably about the same either place, and we have been selling at about 2 cents per kilowatt hour.

Hank Coffer: Thank you very much Susan for a beautiful presentation.

Comment (H. Coffer, EG&G) on EPRI: I didn't want to get in this political discussion about Gladys McCall versus Pleasant Bayou, but there was one other thing neglected in the discussion. Gladys was going to serve as a backup in case we couldn't get that bridge plug out of the hole. The bridge plug came out of the hole and so it does appear that Pleasant Bayou is going to be a viable well. There was a good chance that we'd never get it reopened and that we'd had to go to Gladys McCall. But the bridge plug is out of the hole now and the 5-1/2 inch is out of the hole, which means that we are going to be able to use it for the EPRI experiment.

Comment (Evan Hughes, EPRI): You might also mention that the access to Pleasant Bayou is much easier for purposes of this demonstration.

Comment (H. Coffer, EG&G): Yes, the access for people to go out and watch the light bulb burn is much easier. And it is also much cheaper for people to get out there. You can hire people right in the area and they live there, whereas Gladys McCall, unless you're Cajun, very few people live out in that area. You have to import your workers from Lake Charles or Lafayette or somewhere like that. At Pleasant Bayou there is a town just seven miles down the road. So the logistics favor Pleasant Bayou. The real problem with Pleasant Bayou was the bridge plug. And that's already been answered - it is out of the hole now.

GLADYS McCALL WELL STATUS — Tom Meahl, EOC

Question (Charles Gilmore, DOE-ID): What is the difference between the two curves? What's the top curve and the bottom curve?

Answer (Tom Meahl, EOC): The curves are the high and low readings from the Geiger counter used for the I-131 readings.

Question (Frank O'Brien, WKT): What is the current price of gas that you get?

Answer (Tom Meahl, EOC): The current price is about $1.93.

Question (Mr. McCluskey, AMOCO): I've heard several times that there's 30,000 barrels of water per day, but I've never heard how much gas you're going to have.

Answer (Tom Meahl, EOC): About 758,000 cubic feet per day. This varies of course with the production.

Question (?): Is this pretty constant?

Answer (Tom Meahl, EOC): Yes, it is pretty constant.

Question (Ben Eaton, EOC): Tom, are you getting any oil?

Answer (Tom Meahl, EOC): Yes sir, we are getting some oil. We are getting about a quarter of a barrel of distillant out of our cooler a day and we are getting 12-15 gallons of very heavy oil. It's got a pour point something in excess of room temperature. In other words, if it gets down to about 100 degrees it gets thick enough that if you turn it upside down it won't pour.

Question (?): When did that start?

Answer (Tom Meahl, EOC): As far as I know, it's been there forever.

Question (Dave Riney, S-Cubed): How did you tell?

Answer (Tom Meahl, EOC): While we've been reworking the well, we isolated one of our blowdown tanks and we drain off every day so we can measure what we get.

What was the difference in bottom hole pressure from when it was adjusted... Hank said "that will probably be discussed by Riney. He will be talking about that when he talks about the reservoir performance. There has been, of course, a thousand pound drawdown or something like that in the reservoir".

Question (?): When you said there was no sand over the perforations, how did you know that?

Answer (Tom Meahl, EOC): I ran a dump bailer on a wireline until I hit bottom. It has a measuring device on it. I hit a clean bottom. I recovered nothing there. I did the same thing in the disposal well where I got sand back. That's about 26-feet of perforation. But on this one I went all the way through the perforations, then I calibrated the wireline so I knew where I was.

Question (D. Riney, S-Cubed): Did you notice any sand along the perforation...you can't tell that can you?

Answer (Tom Meahl, EOC): No. The well is shut in, I don't know that. I could find out but it would be a very expensive test.

Comment (Hank Coffer, EG&G): It's been a rather unusual well and we're all very pleased with being able to flow it this long at this rate. Ben Eaton and I are having fights every day about when it's going to fall apart. Right Ben? We've even got a steak dinner on it too.

Comment (Tom Meahl, EOC): I've already got mine.

<u>GLADYS McCALL SCALE INHIBITION</u> M. Tomson, Rice University

Question (Phil Randolph, IGT): Regarding bottom hole pressure at Pleasant Bayou - does pressure have any effect on precipitation of the scale?

Answer (M. Tomson, Rice Univ.): No. Glad you asked though. Quickly now, the formation is calcite cemented. Consequently, it is already nucleated and the activation energy for nucleation has already been spent so you are really precipitating calcium carbonate on calcium carbonate. Consequently, there is virtually no inhibition level and consequently scale takes place essentially continuously, if it can take place. And the assumption we used in the analytical solution, Phil, was to assume that the saturation index maintains zero at all points as the radial distance out in the formation itself. Then we used early data in terms of the actual well production data and so forth. Does that answer your question, Phil? In other words, there is no pressure limitation at which scale begins. In the formation, it should take place continuously at all times when the formation is calcite cemented.

Question (James Fairchild, Dowdle, Fairchild & Ancell, Inc.): What is pseudoscale?

Answer (M. Tomson, Rice Univ.): Glad you asked. This is your time not mine. Guy Lusac, you know Guy Lusac's gas law back in the 1800s. Guy Lusac came up with a rule of thumb in about 1800 that inhibitors of scale precipitation will be insoluble salts of the scale itself. Pseudoscale simply means that the inhibitor's calcium salt is becoming the problem and not the solution. Hence, it is called pseudoscale. That's the short of it.

Question (Frank O'Brien, WKT): A generic type of conclusion was reached that acid treatment was more cost effective under certain circumstances than inhibitor. Does this apply to the DOE design well in any way?

Answer (M. Tomson, Rice Univ.): Absolutely not. The economics of that are diluted to about $400,000 a year to remove scale by repeated acidizing. And that's neglecting all problems of safety, problems of mechanics, and so forth.

Question (Frank O'Brien, WKT): So there's a narrow range in which scale removal is cheaper than inhibition.

Answer (M. Tomson, Rice Univ.): A very narrow range.

Comment (Ben Eaton, EOC): It is strictly limited to a poor boy operation where you can basically dump the acid. You can't have any high pressure...

Comment (Dave Lombard, DOE-HQ): There's also the question of the production that you lose when you shut in to acidize. And, if you have to do that frequently, there can't be significant economic savings.

Question (Bob Shopland, RCS Geotechnical): When you compare the cost of squeeze versus the acidizing, what's the affect on down time? You said one was four times a year and the other 26 times a year. What's the affect on down time?

Answer (M. Tomson, Rice Univ.): Ben can answer that. Sundar told me not to get into this economics stuff. Ben, would you have a comment on the down time, on the relative rate, down time loss, and so forth on acid versus inhibitors.

Answer (Ben Eaton, EOC): I'll refer that to Tom Meahl.

Answer (Tom Meahl, EOC): I'll give this a try. About every two weeks you could shut down and do an acid job. By the time you get the well reduced in rate and you get it back on, you're going to lose at least a day's production. With this happening 26 times a year, you've lost a lot of gas production. With the inhibitor you're going to lose about three days, and these scale treatments are like every six months, maybe even longer...that's as close as I can come for you.

Question(?): Cost of down time?

Answer (Tom Meahl, EOC): All right, I'm looking at $400,000 for the acid treatment and pill treatment, $40,000.

Question (Jack Ramsthaler, EG&G Idaho): Tom, when you enter a well, you run a risk of doing a lot of damage. When you do that 26 times a year, it seems to me as impossible.

Answer (Tom Meahl, EOC): Well, you don't mess up, or you're going to lose your well.

Comment (Hank Coffer, EG&G): I think Ben put it in perspective when he said about the only time you could afford to do an acid job is an operation where you just pour the acid in. If you have to go to high pressure equipment, then the economics really flip over the other way, and you do it as infrequently as possible.

Comment (Phil Randolph, IGT): I just wanted to add a tiny thought to that answer. The situation that Ben and Tom are at, and the situation at the Gladys McCall where the well is geopressured, when you pump in at high pressure and you open a valve, the well comes back at you. A lot of Mason's discussions are on the Hitchcock reservoir which is now subhydrostatic. I'll go into details when I talk about it tomorrow afternoon, but very briefly, if you use the inhibitor squeezes, you stop four days to a week of production. The acid treatments are being accomplished in a day with simply no loss of production. I'll give the details tomorrow afternoon.

Comment (Hank Coffer, EG&G): So it's going to be well dependent.

Question (James Fairchild, DF&A): Based on a draw down calculation, what difference does that make in flow rate? On a high productivity well, when there is 20 lbs. in a calculated bottom hole pressure, there can be a big rate difference in the formation.

Answer (Phil Randolph, IGT): The only thing I can calculate is from the surface measurement and the tubular diameters. If you scale up the tubulars, you reduce your diameter and calculate ridiculous answers down here. That's a good number for the flowing bottom hole pressure inside the casing. You have to tell us what the flowing bottom hole pressure is just outside the skin. It is going to be a few hundred psi higher. Skin drop is not a factor in this calculation procedure. If we got together, we could work it in if you wanted to. But at the moment, skin drop is not in this thing and that figure is in between the psi pressure you're talking about.

Question (James Fairchild, DF&A): I understand that, but what, for example, what's the barrels per day per psi out in the formation?

Answer (Phil Randolph, IGT): I simply haven't done a PI on this. We could do it but I haven't. I don't have an answer. The real reason we wanted to run this calculation is the bottom line. From the brine ratio and some additional work going on, we do not believe that this reservoir has yet been drawn to its bubble point. This reservoir was not saturated before man got there. EBT work back in the beginning of this test, by local laboratories at Lafayette, suggested that the gas brine bubble point was probably about 9200 psi. Terry will suggest that we are just getting to the bubble point in conjunction with this draw down in terms of field data. It is starting to look like the bubble point from field data is going to be damn close to the bubble point from EBT a few years ago. And this sucker hadn't gotten there yet. That's been our big motivation, to try to come to an understanding of bottom hole pressure history.

Question (Hank Coffer, EG&G): You're talking about the bubble point right at the well bore and not out in the reservoir?

Answer (Phil Randolph, IGT): We are simply talking about the bubble point in the reservoir.

TERRY OSIF GAVE HIS PORTION OF THE PRESENTATION HERE.

Question (Mason Tomson, Rice Univ.): You referred to the fact that the hydrocarbons could be forming small bubbles, then bursting out and so forth? No, you weren't? I thought you were saying they might be coming out near the well bore region.

Answer (Terry Osif, IGT): No, what has happened is that gas was dissolved in the brine further out in the reservoir. As it approaches the well bore it undergoes a pressure reduction, and the gas that dissolved in the brine further out in the reservoir comes out and is liberated near the well bore. But the volume is so small that it can't flow and is trapped in the pore space.

Answer (Phil Randolph, IGT): But once you get enough, the bubbles join each other and you get gas flow and that's that spurt of different chemistry you are talking about.

Question (Mason Tomson, Rice Univ.): May I pursue the question? That's what I thought you meant. Now if I understand, that would be a periodic phenomena?

Answer (Terry Osif, IGT): Depending on conditions. You see, this happened when the flow rate was increased which resulted in the decrease in the bottom hole pressure, which allowed the gas saturation near the well bore to increase, allowing the flow. If you produce at a constant rate, I can't see how the gas saturation is going to get much above critical. Because when it gets above critical, it flows.

Question (Mason Tomson, Rice Univ.): Terry, what I'm trying to do is look for an explanation for the observed periodicity in the Pretz field pursuant to your explanation of the timing.

Answer (Terry Osif, IGT): The Pretz form is completely different than this.

Comment (Mason Tomson, Rice Univ.): I know.

Comment (Terry Osif, IGT): We'll talk more about this tommorrow.

AFTERNOON SESSION, MARCH 4, 1986 - 1:30 - 5:00 PM

GLADYS McCALL RESERVOIR GEOLOGY REVIEW C. Groat, LSU

Question (Hank Coffer, EG&G): There's a pretty good chance of intersection of these various ends somewhere fairly close to the reservoir?

Answer (C. Groat, LSU): Hank, just based on anything analagous in modern systems to produce that thick a sand, I think there's an excellent chance of their interconnecting. The shale sequences that appear in this are very apt to be at least semi-lenticular, in other words limited to the extent sand would be more apt to be connected laterally.

Question (D. Riney, S-Cubed): What you have to understand... that they expect to have numerous faults... Is that possible?

Answer (C. Groat, LSU): Very possible. The thicker sand sequences in the coastal environment depositional setting can be strike oriented. Essentially east-west stack barrier sands, that sort of thing. Most of the sand bodies that are dip-fed that are flutial tend to be thinner, more limited and do not extend very far east-west. In this system it looks more like a strike-fed system where you get more lateral extent than north-south extent.

Question (D. Riney, S-Cubed): Looking at the pressure temperature of the strike, I'm almost forced into this kind of a model (conceptual model) you described...

Answer (C. Groat, LSU): Based on closely calculated analog, I think it makes a lot of sense.

Question (Phil Randolph, IGT): Please comment on the geological implications of the significance of the reservoir brine not being exactly saturated with methane. Isn't that sort of surprising because of the sand shale ratio?

Answer (C. Groat, LSU): That's a question I'd just as soon not answer. It doesn't tell me anything, Phil, I'm sorry.

Question (Bob Shopland, RCS Geotechnical): What is the period of the microseisms associated with the events?

Answer (V. Van Sickle, LSU): I have a plot showing the difference that I can show you after. I'd be glad to get it for you. It's just a plot of, you know, a record of the typical noise activity we saw versus the 13 earthquakes that we recorded.

Question (Bob Shopland, RCS): There were at least 10?

Answer (V. Van Sickle, LSU): There were. It is really confusing because first the contractor we had thought they were definitely earthquakes. And our seismologist down on staff really spent two years looking at the data and he thought they were strictly related to weather.

Question (Bob Shopland, RCS): At 6,000 feet, with casing in the wells, did it contaminate the formation or the surface?

Answer (V. Van Sickle, LSU): The surface. The ground water. The shallow groundwater. The whole purpose of the groundwater monitoring was to monitor the quality of the domestic and agricultural water that was used locally. We didn't go any deeper than people were using and relying on for their domestic water supply. So, we don't know if something happened down deeper or not.

Question (Frank O'Brien, WKT): Do you expect, based on modeling, to see any subsidence in Gladys McCall as production approaches 20 million barrels?

Answer (V. Van Sickle, LSU): I wouldn't. I'd hate to guess before we get the data. If we see it anywhere, Gladys McCall should be the most interesting to look at.

Question (Bob McClusky, AMOCO): Are there any changes observed in organics in the water?

Answer (V. Van Sickle, LSU): I'll refer that to Dru Trahan.

Answer (Dru Trahan, LSU): There have been no appreciable affects on organic contents.

PLEASANT BAYOU REWORK T. Meahl, EOC

Question (Dave Riney, S-Cubed): What are your plans on reperforating?

Answer (T. Meahl, EOC): My plans on reperforating are to first bring the well in and see what we have. Sometime next fiscal year, if it appears necessary, we'll go ahead and reperf. We can do this at any time.

Question (Frank O'Brien, WKT): Are you going to flow the well now? Are you going to put in the tubing now?

Answer (T. Meahl, EOC): I'm going to put in the tubing now and complete the well, Frank, when I get all the junk out and get it cleaned up. This pipe has been purchased.

Question (Dave Lombard, DOE-HQ): Is it on site yet, Tom?

Answer (T. Meahl, EOC): No sir. I don't want it down there yet. It's much better in Vam's warehouse here in Houston.

Question (Phil Randolph, IGT): Tom, what's your best judgement on where that seal assembly came apart in relation to the top of the packer?

Answer (T. Meahl, EOC): It was above the top of the packer. I have 6-11 feet above the packer. I got 3 feet of it milled off last night and in a couple of days we'll be ready to run something in there and pull it out. That's where we stand today.

Question (Hank Coffer, EG&G): Tom, the disposal well, is it clean?

Answer (T. Meahl, EOC): Negative. It has to be cleaned. That is a strange breed too. They had a failure in the 13-3/8 and ran 9-5/8 on it and completed in the 13-3/8 so its nice and easy to get to to clean up.

Question (Frank O'Brien, WKT): Once you finish cleaning out the well, are you going to run the 5-1/2 in so you have a full size well ready to produce at the surface?

Answer (T. Meahl, EOC): That is correct.

Question (Frank O'Brien, WKT): Are you then going to mud up or are you going to leave the well live?

Answer (T. Meahl, EOC): I'm going to leave the well live at the surface.

Question (Frank O'Brien, WKT): How much sand is in the injection well?

Answer (T. Meahl, EOC): At least 75 feet and I don't know, with all the scale they had, what condition the well is really in.

Comment (Frank O'Brien, WKT): Tom, I think it's fantastic what a good job you fellows did in getting that well fixed up as quickly and inexpensively as you've done. We certainly expected a lot more trouble, and you've obviously done a good job. Certainly one to be proud of.

Answer (T. Meahl, EOC): Well thank you Frank. We've been lucky.

EPRI EXPERIMENT STATUS Evan Hughes, EPRI

Question (Charles Gilmore, DOE-ID): You mentioned earlier that you were working with Houston Power and Light, is that right?

Answer (Evan Hughes, EPRI): Right.

Question (Charles Gilmore, DOE-ID): What have you negotiated as a cost of electricity, sales price or anything yet?

Answer (Evan Hughes, EPRI): No. Better than that. They have agreed to install the substation that will be required to connect to their grid. And they will pay for that and then get repaid by free electricity until the value of that electricity equals what they've had to spend to install the substation.

Question (Charles Gilmore, DOE-ID): What are they valuing the electricity at?

Answer (Evan Hughes, EPRI): As I indicated this morning, a couple of years ago it was at four cents a kilowatt hour and it's on its way down. I don't think it will be below two cents a kilowatt hour. I think if we can get 2-1/2 cents a kilowatt hour, it is the best we could expect.

Question (Frank O'Brien, WKT): Evan, is there any other work going on relative to this hybrid cycle? Is this the only one that could legally be called a hybrid or are there other EPRI efforts similar?

Answer (Evan Hughes, EPRI): No, this is the only EPRI project of this sort. DOE is involved with a wood-burning geothermal power plant project in northern California which I'm not sure is going to go forward. There are some differences between that cycle and ours. The basic one being that that's a steam cycle rather than a binary cycle.

Comment (Dave Riney, S-Cubed): Also, in the oil fields in California there are a number of coal generators, where they're burning heavy oil to make steam.

Answer (Evan Hughes, EPRI): That's not the same sort of combined cycle. Our idea here is to investigate how you can improve both the combustion cycle and the geothermal cycle by putting them together, and in particular for these lower temperature heat sources such as the 300°F heat source we'll have here. We've done some studies to look at the benefits of this kind of cycle at different temperatures of geothermal resources, and it looks like the benefit depends upon the temperature of the geothermal resource and on the heat rate on which you can do the combustion cycle. We've looked at about 9,000, 11,000 and 14,000 BTU per kilowatt hour heat rates, and the advantage of the hybrid system over separate combustion plus separate geothermal is on the order of 20 percent at the middle part of that range. That's the additional work you can get. Studies in the past have suggested this would turn into about a 10 percent advantage in bus bar electric power. In addition to that possible cost and efficiency advantage, I think that for using some low temperature geothermal resources, the possibility of having this backup system, if you will, in a hybrid concept might be helpful in getting some new geothermal resources to be employed that would otherwise not be put into use.

Question (Dave Lombard, DOE-HQ): If you're selling electricity, for say 2 to 2-1/2 cents a kilowatt hour, what would you anticipate the cost for generating it? Assuming that this is an experiment, but if you were to carry that forward, can you generate it for that?

Question (Hank Coffer, EG&G): Assume the hot water is free, what would it cost you?

Answer (Evan Hughes, EPRI): Let's see, paying a $1 per million BTU for the fuel, I came out with about 6 cents a kilowatt hour.

Comment (Charles Gilmore, DOE-ID): You have to recognize that 2 cent electricity means we don't want electricity. That's what that means. Nobody can generate 2 cent electricity in the country. That just means that we don't want electricity. We are only taking it because you're a friend and we want to help you out. If anyone's going to tell you, "I'll give you 2 cents for electricity, and that's all", he's telling you I don't want to buy any electricity. So what that says is this whole United States right now is in an electricity surplus not an electricity demand situation. And right now a person would not be very prudent, I don't think, to go out and generate electricity and try to sell it at this point in time unless you are in a certain situation where it is in demand. And there are very few places like that right now in this country. But in the future, if the economy ever turns over and certain things ever happen, and we get in a demand situation again, then that's what we're looking at for this type of situation.

Comment (Dave Lombard DOE-HQ): No, I understand that. I was just kind of curious as to what it really would cost.

Comment (Charles Gilmore, DOE-ID): Nobody's going to generate electricity off of geothermal for 2 cents.

Comment (Evan Hughes, EPRI): I think with a free heat source, my number would probably come out about 4 cents.

Question(?): I guess when you say you've done your studies, is it a lot like early studies that were done say with enhanced oil recovery? If the price of oil goes to $10 we can afford to put this process in, or if everything comes along with it such that at $10 we still can't do it for $20 or at $20 we still can't. In other words, your cost of fuel will go up. So how do you develop the real differential which says what the process costs.

Comment (Evan Hughes, EPRI): What we've done is simply an evaluation of the efficiencies that I mentioned. Certain heat rate for the conversion for the combustion cycle. Look at how many watt hours you can produce in the pound of geothermal fluid at the temperature involved, then compare them separately with the hybrid. That's where I get about 20 percent improvement. What that turns to in dollars depends upon your price of fuel. That's what that heat rate means in cost.

Question (Hank Coffer, EG&G) to Jack Ramsthaler: Jack, haven't your people done some calculations on this?

Answer (Jack Ramsthaler, EG&G Idaho): Well, I think that is the answer. You can have a lot of alternate energy sources, and whatever the true price of finding oil is, it starts to get more difficult than it is now no matter how OPEC runs it. This is one of the first things that is going to be coming down. It looks better than synthetic fuels.

Question (Hank Coffer, EG&G): You've assumed that the well was already there?

Answer (Jack Ramsthaler, EG&G): Yes, assuming the well is already there.

Comment (Hank Coffer, EG&G): In other words, somebody drilled a wildcat and didn't hit, but they hit a geothermal pocket, then it becomes a dollar intensity thing.

Comment (Charles Gilmore, DOE-ID): We can tell you what the capital cost to produce electricity is once we get through with these projects, but what the revenues are going to be is strictly market.

Answer (Jack Ramsthaler, EG&G Idaho): Gladys McCall was almost, well it was paying for itself for a while until the price of gas kept going down until it was no longer economic.

Comment (Dave Lombard, DOE-HQ:): You're making a commercial statement that isn't true. The cash flow from the gas flow at Gladys McCall was paying some of the experimental operational costs. It did not include paying off the millions of dollars for the drilling costs.

Comment (Hank Coffer, EG&G): He meant given the well was free.

Comment (Dave Lombard, DOE-HQ): Well, you give me one, I'll take it.

ANALYSIS OF LIGHT HYDROCARBONS FROM DOE WELLS — Dean Keeley, USL

Question (Terry Osif, IGT): What was Zerella?

Answer (Dean Keeley, USL): Zerella was with Gulf R&D. Gulf Oil had producing fields in various places in the West and in Canada. They have drilled other wells (relatively shallow wells--so it's not that expensive) in order to prove their field. He had taken drill stem tests and had them analyzed for various materials, one of which was benzene primarily. He had discovered that the concentration of benzene varied with respect to the distance from a producing field, and he had data points up to a number of miles. Not short distances.

Question (Dean Keeley, USL) directed to Terry Osif: What else about it Terry?

Answer (Terry Osif, IGT): He found that there was variability in the amount of benzene among certain fields. But, in a particular field, the nearer you were to gas the less benzene was found in the oil brines.

Question (Dean Keeley, USL) directed to Terry Osif: What temperatures were their fields?

Answer (Terry Osif, IGT): They were not geopressured fields, they were conventional oil fields.

Question (Dean Keeley, USL) directed to Terry Osif: Are they fields that could have been deeper and have now come up so that the chemical composition is frozen in time?

Answer (Terry Osif, IGT): He found benzene in the brines that were in the oil producing reservoirs but not in those that the reservoir only produced gas.

Comment (Dean Keeley, USL): Yes, there was no benzene in the brines from gas producing reservoirs. He did not look at any in the Gulf Coast region and they were all much shallower, were they not, several thousand feet.

Answer (Terry Osif, IGT): Yes.

ANALYSIS OF HEAVY HYDROCARBONS FROM DOE WELLS

Dean Keeley, USL presented for O. Weres who could not make it.

Question (Mason Tomson, Rice Univ.): Are there any small pore structures in the formation of the fields? Are there fine bottleneck pores?

Answer (Dean Keeley, USL): You'll have to ask the people who have made the observations on the pores around here.

Question (Mason Tomson, Rice Univ.): That's the argument, are there gas filled bottleneck pores?

Answer (Dean Keeley, USL): Yes, you mean if there's a small, small space in there, it may be gas occupied and you get a partition. Then as you drop the pressure, they expand and eventually move. That's perfectly valid thinking. There has to be something responsible for the kind of variation that we're observing and we're just dying to know what it is. If anybody has any ingenious ideas, please let us know.

Question (Mason Tomson, Rice Univ.): Has anyone looked at pore structure in detail on intergranular structure of these formations?

Verification (Dean Keeley, USL): Electron microscopy or something of that nature?

Comment (Mason Tomson, Rice Univ.): No, I suggest someone have a look at it.

Question (Dean Keeley, USL): No, I have no idea. Who did it? Terratech? They're not here.

Comment (Phil Randolph, IGT): To partly answer your question Mason, the work done in various labs consistent with this general model that the industry is familiar with is sand with permeability up in the range of 10 to 100 millidarcies. Then you tend to have relatively rounded grains cemented together with intergranular space and roughly half a dozen flow paths between grains. In the case of the Gladys McCall sand, it doesn't look like primary porosity--it's not secondary porosity like over at Pleasant Bayou where they've been dissolved out. Bunch of balls with a little epoxy on it and they face between the balls and half a dozen channels connecting to get relatively conventional primary porosity.

Comment (Don Clark, Consulting Petroleum Engineer): Most of these sands, as I've looked at geopressured in this area, have high permeability. There is normally very little cementation, it's all compaction, and you see where each sand is indented in the next sand grain.

Comment (Phil Randolph, IGT): Quartz to quartz cementing.

Comment (Don Clark Consult. Petr. Engr.): We don't find any cementation in it at all under the microscope.

Comment (Dean Keeley, USL): The high permeability is what bothers us.

Comment (Don Clark, Consult. Petr. Engr.): The ones with pores showed the highest permeability. At Pleasant Bayou, we picked the one that had high permeability. At Sweet Lake, we picked the sand that had the high permeability. At Gladys Mccall the same.

Comment (Dean Keeley, USL): We're convinced of this, whatever we're looking at is a fundamental process that is occurring all along the Gulf Coast. It's not anything that is unique to one formation. It is a standard process because the materials you get are all the same.

Comment (Don Clark, Consult. Petr. Engr.): We know one thing, though, that all the sands we are looking at for geopressured are usually associated with thick shale beds.

Comment (Dean Keeley, USL): The thing that they have in common is that thermally they are not that far apart. They are all in that portion of the overall geochemical process that we referred to as the last quarter of the catogenesis state before you start going into metogenesis. They all have that in common.

Comment (Don Clark, Consult. Petr. Engr.): There is one thing when they're cooling in the Gulf Coast area, when they are in the shelf area, a lot of shales and sand. A lot of the time we do find that the shales are black, and they have oil in them.

Comment (Dean Keeley, USL): The process is probably still going on. I mean it's a doubtful process. If the geochemistry of the process is understood, the process is still going on.

<u>GLADYS McCALL RESERVOIR ANALYSIS</u> D. Riney, S-Cubed

Question (D. Lombard, DOE-HQ): Dave, if I can read your graph from here, it looks like as you said this morning, we produced like 16 million barrels out of there.

Comment (D. Riney, S-Cubed): I haven't updated it, but I think it's pretty good.

Question (Hank Coffer, EG&G): So how big is the reservoir?

Answer (D. Riney, S-Cubed): I don't know how big it is. If you guys realize, reservoir limit tests have their limits. We get the first estimations here, but anyway, based on that model, it predicts a reservoir of 2-1/2 to 3 billion barrels. It hasn't changed in a long time. I've used the same model as far as the first 500 meters near the well bore or more than that. I haven't changed that since the first buildups.

Question (Hank Coffer, EG&G): Which curve are you predicting on now for production?

Answer (D. Riney, S-Cubed): All three of them. They're at all different places. If you measure the bottom hole pressure, it's the middle curve. Read to the left. What you're interested in is the wellhead pressure and that's the bottom curve.

Question (Don Clark, Consult. Petr. Engr.): Why don't you put today's data on there?

Question (D. Riney, S-Cubed): What do you mean?

Comment (Don Clark, Consult. Petr. Engr.): Tom Meahl knows what the pressures and flow rates are.

Comment (D. Riney, S-Cubed): What is it today, Tom? Around 30? Around 10,000 psi as far as I can read on this thing and then 15 million total production. The thing you have to remember is that we're getting down to the point where this curve is starting to level out. So we're saying over a period of a lot of production, the pressure drop is not very many psi. I don't know, 50-100 psi so that's a lot of barrels of production.

Discussion on the graph.

Question (Don Clark, Consult. Petr. Engr.): Are you using flowing pressure?

Answer (D. Riney, S-Cubed): I'm using flowing pressure all the way, but I look back at my data and my calculations and the differences between wellhead pressure and bottom hole pressure were up to 650 psi. I looked at all that history and looked at the difference between the flowing pressure and the bottom hole pressure, and it's around 650 all the time so I just use 650.

Question (Don Clark, Consult. Petr. Engr.): What I'm saying, I think you are actually better with flowing pressure on the surface than they are on the Pleasant Bayou. We show that after 20 days of buildup time, the surface pressure was drawing down like 30 psi per cycle while the bottom hole pressure was going up 55 psi per cycle.

Comment (D. Riney, S-Cubed): That's the reason I showed this. I know exactly what you are saying. Here I've shown the change in pressure at the well bore, and it is true that if you wait 10 or 15 minutes before you make that measurement, you can see it's no longer a constant value but changes very rapidly. And if you got out 20 hours, you aren't measuring bottom hole pressure at all.

Comment (Don Clark, Consult. Petr. Engr.): You also said, I believe, that your last effort was around 290 bottom hole temperature or less.

Comment (D. Riney, S-Cubed): I don't remember the number, it gets higher each time.

Question (Don Clark, Consult. Petr. Engr.): You have a much higher temperature close to the bottom hole now, and are going to have all the corrections that you would have?

Answer (D. Riney, S-Cubed): That's right. In fact, I estimate that we saw 30 psi here. I think there is as much as 75 psi difference between the surface pressures during shut in.

Comment (Phil Randolph, IGT): We noticed that temperature rise in the field while work was being done. The man on the truck operating the equipment was the same guy who had been there the previous time. (Let's go back of the room and talk about calibration.) The temperature you're reporting at Sand 8 is the same temperature that used to be at Sand 9 two years ago. Would it be valid for me to draw from your temperature data the conclusion that the packer is gone and that we've got to go set a new packer because we are not testing what we think we are testing?

Comment (D. Riney, S-Cubed): That's not what I asked about.

Terry Gardner said that. If you just look at the data, looked at the temperature, I think you could convince yourself that under steady-state conditions, the temperature is a little higher. Not a hell of a lot. But it's several degrees. I don't know where it's coming from but it makes one feel like that the reservoir is not only flowing from above, but below, where it is hotter.

Question (Don Clark, Consult. Petr. Engr.): Are you sure you're always going to the same depth?

Comment (D. Riney, S-Cubed): Well, only that the people who report it, and the fact is that the measurements are very consistent.

Comment (Dave Lombard, DOE-HQ): Over the years I've seen numbers of reservoir engineering analyses of what it all meant in terms of looking at the data that we've had available from our well test, and I want to congratulate you. This is the first time I've ever seen anyone make a prediction. Thank you very much. You took a step in the right direction.

PLEASANT BAYOU GEOLOGY REVIEW — M. Light, BEG

No questions on this presentation.

SURFACE WATER QUALITY AT DOE GEOPRESSURED WELLS — Walt Kocher for E. Saleh, Southern Louisiana Univ.

Question (Mason Tomson, Rice Univ.): There was no iron data?

Answer (Walt Kocher, SLU): I'm at a little bit of a disadvantage here. I'm still in my rookie season here on the project, and these kind of decisions were made before I joined on. It might be something we would consider in the future.

Question (Mason Tomson, Rice Univ.): Where was this sample well with the high lead concentration, at Pleasant Bayou site?

Comment (Hank Coffer, EG&G): I suggest he get with you over a glass of wine and give it to him.

DAY 2, MORNING SESSION, MARCH 4, 1986, 8:30 - NOON

LOG ANALYSIS IN GEOPRESSURED WELLS — M. Dorfman, UTA

Comment (M. Dorfman, UTA): This program will be available for anyone.

Question (Hank Coffer, EG&G): How do we get it?

Answer (M. Dorfman, UTA): I'm going to try and get it on ORPHAN NET. We are tied in with ORPHAN NET through our main computing system, and people can access directly with tapes or bring the logs in, and we can digitize them. Or, put it on tape and run analyses and, of course, we can do this for either DOE or GRI very, very easily.

Question (Dave Lombard, DOE-HQ): How would someone in industry get a hold of this capability?

Answer (M. Dorfman, UTA): Well, we are going to put a paper out on it very shortly and make it known to industry. I think they will find this program extremely useful. Many of us have gotten it. It is no secret. Many of us have some computer logs that have been put out as a service by the various logging companies, and we find that in many cases resistivity of water varies over several feet of the sections. In some cases, we find that formation factor values for carbonates or sandstones may be used interchangeably or may be wrong, and the result is that it gives someone inaccurate data.

SALINITY OF WATERS — M. Dorfman, UTA

Question (Frank O'Brien, WKT): What is the impact of the DOE funding problem going to be on the operations?

Answer (M. Dorfman, UTA): Everything is going down about 30 percent.

ROCK COMPACTION — Eric Fahrenthold, UTA

Question (Frank O'Brien, WKT): Are you looking at real reservoir core rocks from the various design wells? Are they all behaving similarly in terms of these non-linear properties or are the individual sandstones behaving completely different?

Answer (Eric Fahrenthold, UTA): We are looking at cores from the Hitchcock well right now which GRI funded. So these are actual sandstone and shale samples from this well. The tests that were done last year and previous to that were also from core samples. We have noticed there is a qualitative similarity between the Pleasant Bayou sandstone and the Hitchcock sandstone. We have noticed some qualitative differences between the shale behavior and the sandstone behavior although the modeling work we have done is capable of incorporating that strength softening behavior on the part of the shale as well as the strength hardening properties of the sandstone. Let's see, what was your last question?

Question (Frank O'Brien, WKT): Basically, are all the design wells, I don't know whether you've looked at more than Pleasant Bayou, are they all similar properties?

Answer (Eric Fahrenthold, UTA): Yes, we've looked at Pleasant Bayou, Sweet Lake and Hitchcock. Their qualitative behavior is similar. Their numeral property measurements vary significantly between wells and we have noted, and Terratech has noted, very significant variations between samples from the same well. So there is significant data spread, but qualitatively the behavior is very similar. I think the interpretation that we made of the Pleasant Bayou data is definitely going to be applicable to this work.

Comment (Phil Randolph, IGT): I'd like to comment on your impression. My impression on rock mechanics failures are putting pressure on a core laying on a bench at one atmosphere to something perhaps in excess of reservoir conditions. A more practicable modeling effort would be heavy emphasis placed on that range of stresses that could conceivably occur during the production of that particular reservoir. You should set up initial reservoir conditions and go through the stress swing you'd run into in a reservoir, just that little swing rather than whole range that you never have.

Answer (Eric Fahrenthold, UTA): Yes, we have conducted the widest possible sweep of tests in terms of pressure conditions to try to look at the material behavior under all conditions. Questions like restoration of the sample in situ conditions would require looking at the material behavior over pressure ranges of immediate interest in reservoir production environment. I think that's a valid criticism. We should probably make more of an effort in interpretation and modeling and less in the future in testing and the appropriate reduction in our testing effort would be as you suggested.

Comment (D. Riney, S-Cubed): I'd really like to emphasize that too. I think that the whole structure of the program would be to simplify rather than to try out all the possible concentrations that you could find. You don't want to look for extra complications, you really want to look for simplifications. I really would urge that for the rest of the tests you try to see if any generic simplification can be made.

Answer (Eric Fahrenthold, UTA): I agree. I think from an academic interest you would want to look at the widest possible range, but I think if you look at our December progress, it is a major step in simplifying this tremendous volume of data and that it doesn't answer everything, but it reduces the description of the material behavior to a small number of material coefficients and some non-linear stress/strain relations which address in part that question.

Question (Jim Fairchild, DF&A): On all your tests you show a hysteresis where you've loaded, unloaded, loaded, and unload. Are they repeatable, or is there a scanning route that you've got?

Answer (Eric Fahrenthold, UTA): We have done cyclical tests. What has occurred is the material even if we loaded only a small amount then unload, we see hysteresis and even if we loaded only a small amount and unload we see a small amount of residual strain there. So, what we get is a series of hysteresis loops if we load, unload, load, unload. There are two things, two properties or two observations, which have helped us in the modeling in this behavior that is going on right now. One of them is that the material, although there is hysteresis upon each unloading/reloading cycle, it returns that the loading curve returns to this kind of original reloading. In other words, if we load and unload this material, we load it a small amount then unload, you'll see a hysteresis but when we reload, it will return back to this curve. Of course we can't say, since its a reloaded sample onto a separate history, we can't say definitively that that was the same reloading curve, but it is certainly a reliable assumption based upon the similarity of the curve that appears under loading and reloading to this kind of one cycle test. And also, if I could mention one more, this unloading curve is described by a relation which gives the stress as a quadratic function of the strain. Now that is very important in terms of data reduction, and also, it is consistent with non-linear elasticity theory. Of course, this unloading should be the relaxation of a sample as its inherent elastic properties. So if we unload and reload several cycles, we get a simple shape to this curve. We are still doing the analyses, but I think we will be able to extract from a single cycle like this electric properties which would consistently describe these numerous unloading cycles. That means that we are going to need fewer material properties to describe that cyclical loading behavior.

Question (Jim Fairchild, DF&A): Put your finger down on the unloading curve down at zero stress. Now start loading. Where are you going to go?

Answer (Eric Fahrenthold, UTA): It's going to go up like this. We are going to get a hysteresis loop in that it's not going to load directly up this line. It loads with a shape similar to this curve. Concave downwards. It does return to this line, however, not linearly but with a concave downward shape and if you repeat the cycles, it would continually go to this curve.

Question (Jim Fairchild, DF&A): So with your unloading curve that you have there, is it going to keep shifting?

Answer (Eric Fahrenthold, UTA): Yes, definitely.

Question (Jim Fairchild, DF&A): I want to go back up on the curve that you have there. In other words, if you were to trace from zero and go up the loading curve then come back down, you're going to be to the right. How far will that go?

Answer (Eric Farenthold, UTA): I'd say roughly, over the ranges that we've tested, this incremental plastic strain we get with each cycle is approximately linear with the incremental stress. That is if we load up, let's say 500 psi and unload, we get a certain amount of plastic strain. Now we load up to 1,000, that is an additional 500, we get an additional plastic strain, and that change in the plastic strain with each cycle for equal incremental stress changes is approximately linear. Now ultimately, we know that this curve is going to flatten out, but it again gets into the question what stress range do you want to load this material? For a brittle material, the rocks we have tested show that what happens when we load further, we'd get a peak in this curve and a downturn and then fracture. And for a very large ductile behavior, behavior at large stress pressures, what we get is a gradually increasing curve ductile behavior, very large strains, and a failure of the sample without a kinking of the stress/strain curves.

Question (Jim Fairchild, DF&A): What I'm having trouble with is that you've come off from the unloading curve and go back to your loading curve, but you only go to the same end point stress that you have on there.

Answer (Eric Fahrenthold, UTA): I don't claim that we go back to that.

Question (Jim Fairchild, DF&A): You go back to that curve, then we track that curve up, right?. Does that mean that eventually we get then, because of these loops, we get a vertical line?

Answer (Eric Fahrenthold, UTA): No, we don't get a vertical line.

Question (Jim Fairchild, DF&A): You're getting a shift then in your loading curve.

Answer (Eric Fahrenthold, UTA): In other words, if we went on continuing this test and reloaded, we get a reloading curve which has a concave downward shape and returns to this curve. Okay, we unload again.

Question (Jim Fairchild, DF&A): No, take it all the way up to the bullet.

Answer (Eric Fahrenthold, UTA): Okay, you are asking, would it go to here? No.

Comment (Phil Randolph, IGT): You're asking the wrong question, Jim. Let me take a crack at this. You've got a rock laying on the bench. You put it in your machine. You load that sucker up to the native state of the reservoir produced fluid, say this point like here. Now if you start simulating reservoir fluid withdrawal, that would increase the stress on the rock and you'll march up this curve. Now if you start talking about some recharge of the reservoir taking the fluid pressure up, that's when you'll get into one of these jobs that dips down here somewhat. Now take it back up and it's going to come back to this point.

Question (Jim Fairchild, DF&A): You're saying you get in the same scanning loop.

Comment (Phil Randolph, IGT): We could draw the reservoir down some more, you'll march up this curve and you'll get a new scanning loop.

Question (Jim Fairchild, DF&A): So the scanning loops are repeatable?

Answer (Phil Randolph, IGT): Yes. This is why I worry about what would happen if you really address this type of question, because it's sort of related to a very different thing where we focus hard on what can happen in the real reservoir. We come to a permeability story which would carry over into this and say that what you've got is a slope you can describe this rock by and you've got another parameter saying that slope intercepts a straight line. When you've got a couple parameters you put in, you've got that sucker.

Comment (Eric Fahrenthold, UTA): Let me say just one thing. This we have not done. What we have done, because I understand your point now, what we have done is this. We've loaded, unloaded, loaded to a higher so naturally we expect a change in so-called plastic strain. Just as you mentioned, we should come down to here otherwise it's going to essentially drop vertically. But, let me make one other point in regards to that, that is the question of time dependent behavior. We label this always residual strain as opposed to plastic strain because it's a residual strain in the sense that it is conceivably recoverable if we wait long enough.

Comment (Jim Fairchild, DF&A): Let's say geological time.

Comment (Eric Fahrenthold, UTA): Well, maybe not even geologic time. We're getting significant time dependent deformations that were just several months in the pre-test. So the point I'm trying to make, let's say we did this, and we should do it, and we unload down and say we get this. As you mention, that implies that if we cycle it enough, we'll get a vertical line. This distance right here, if we waited a little time, it might go back. That would be physically consistent. The time dependent behavior would be reflected on this curve, that's why we are doing pre-test and that's why that kind of behavior is particularly a problem on the shales on unloading and we're doing creep tests in order to get a better handle on that kind of behavior, but we should do this and see what kind of result we got.

Question (Ben Eaton, EOC): I have a different question but it's related. I've been studying the Dow Sweezy data from the Sweezy well, and I don't think you all did the rock work. It may have been Terratech. They made some graphs like this except they plot the bulk compressibility and core compressibility on the Y-axis and core pressure on the X-axis.

There's this abrupt change. They state in the body of the report that in actual field operations they could never draw the core pressure down to 8,000 psi due to excessive sand production. My question is this. Is this abrupt change in these graphs like that where you have a trend in the behavior, is that failure? And is it failure that we would expect in the field as we withdraw the core pressure, the core fluids out?

Comment (Eric Fahrenthold, UTA): I'd rather term that yielding as opposed to failure, although those terms are taken to be synonomous. What I mean by yielding is plastic deformation. You always have plastic deformation, as opposed to failure. We talk about a sample failure in terms of gross mechanical failure of the sample in its inability to support a load, as opposed to yielding where it experiences plastic deformation, but can still sustain loading. So yes, I would interpret that as yielding, although I'd like to look at the data, I'd say yes and I mentioned well bore stability and sand production. This kind of material modeling is very relevant to the study of those kinds of problems. Now, what we would want to do is go ahead and carry this loading curve further in order to be able to quantify the yielding behavior of the material. In other words, as I mentioned before, if we load this further, we get in many cases a very sharp change in the slope here which is evidenced by a sharp change in these compressibility or mechanical coefficients.

Now there are a couple of points that I think are real important here. One is that with rocks as opposed to metals, you frequently do not see a well defined yield point like we're discussing. You tend to see residual strain present gradually introduced over this entire loading curve as opposed to being dramatically introduced at the point which you get to a particular pressure. In other words, if you look at a simple material model it says if you loaded and unloaded under low stress ranges it essentially returns to its original state. But, once you get to this yield stress, you begin to get a drastic slope change in the loading curve and an introduction of a lot of plastic strain. Rocks are more complex and you generally get this residual strain over the entire loading cycle. You get some even if you just loaded a little bit and unloaded it. So whether or not it comes back, and how fast it does, that's again looking at the explicit time dependent behavior, which is not normally present for metal. Although you get it with metals at high temperatures, but in terms of modeling viewpoint, that tells me we need a different approach. What I think is a step in the right direction is the modeling effort that we have made recently that is in our December progress report. The approach we have taken is to look at stress and total strain on loading and don't try to break the strain down into plastic and elastic parts that you do with metals on loading. We try to shift focus away from the calculation of these moduli, like compaction coefficients and Young's modulus, those are only of interest as a means of predicting the strain. What we really want to know is how the stress changes strain. The only reason we're interested in Young's modulus is because that in the ideal case it gives an exact description of how stress changes with strain. So the problem with calculating these incremental coefficients, although we have done it here in what I feel is the most reliable fashion by calling normal interpolation and calculation of slopes. If we differentiated the data by calculating the slopes of these curves, we get Young's modulus. If we put that into a reservoir model and try to back out strains from those slopes, we get any errors that appear in that differentiation process magnified in the back calculation process in the reservoir model. So the whole point is, what we care about is not the values of the moduli, but how the strain changes with stress. So that's why we want to go to a completely different model. Right now I don't have anything to replace it, although I think our non-linear model is the right direction, and we are working on putting that into reservoir work. But focusing on the slopes, I think is the wrong approach.

Question (Ben Eaton, EOC): Let me ask one more question. Have we done enough work on these cores where we can say when we take the core pressure down to a certain level we're going to expect plastic deformation or yielding?

Answer (Eric Fahrenthold, UTA): Because we can quantify the material behavior from very low stress states up to like 10,000 - 9,000 psi, from low stress levels to reservoir stress level.

Question (Ben Eaton, EOC): Let me ask one more time. We have one set of data where they have some plots that show a yield. And then the field data verify that. I mean it's sanded up tight. It's all over with about the same pressure as the core said it would be. Can we take something like that and apply it to the wells we have now? Is the McCall well going to collapse?

Answer (Eric Fahrenthold, UTA): Let me say one thing and I mentioned this before. Let's say that we test these samples in what we call reservoir conditions. Now the stress state in the vicinity of a perforation say, may be much higher.

Comment (Ben Eaton, EOC): I think it is.

Answer (Eric Fahrenthold, UTA): Then what we need to do, in my opinion, is test these rocks. And we can do that with minimal effort. Do some more tests at higher stress levels to go up and see where this curve peaks for brittle behavior and for ductile behavior, what the ultimate load the material will carry. Because that's the material behavior that is relevant to that problem. What we would do to make a reliable, in my opinion, prediction of, say production rates, is carry these curves up further until we get failure of sample which tells us ultimate strength of material. There are a number of different approaches to the well bore stability problem, and the perforation stability problem. I have worked with John Chittum at Rice and am familiar with how we take a material behavior and put it into models that make predictions about stability. The only piece of information I think we are missing is to look at sand production and formation stability in this well and do a few more tests at high stress.

Comment (Ben Eaton, EOC): Let me explain why I'm asking this question. This piece of rock came out of the Pleasant Bayou well a couple of days ago. There has been no perforating done since that well was produced a few years ago. So maybe this is plastic deformation due to perforations. I don't know, but it looks like it is producing sand. This is the type of problem we're facing, and I think we need to zero in on this so we can see what it is.

Answer (Eric Fahrenthold, UTA): Now I looked at this particular problem of perforation stability with my thesis work with John Chittum. We looked at safe production rates for sands which exhibit exactly this type of problem in porosity extrusion of chalk through casing perforations with what I feel is the most realistically currently employed failure model for rock yielding and certainly if that's of interest to the program, we can do that type of work with a few more tests.

Question (D. Riney, S-Cubed): At this particular time, it is interesting because we talked about your tests. Did they start, are those particular relations based upon taking the specimens to failure?

Answer (Eric Fahrenthold, UTA): What we do is a series of tests which load the material through a tube, for example, in situ state on one end, 9,000 psi axial load, 5,000 psi radial load and some pore pressure slightly below the radial loading condition and incremental stress/strain relations describe a deviation of the sample from in situ conditions. From free stress conditions which range all the way from in situ conditions to much lower stresses, the lower stresses being again to investigate that behavior as we take a rock up to in situ conditions.

Question (D. Riney, S-Cubed): You start out with some in situ conditions?

Answer (Eric Fahrenthold, UTA): From a reservoir modeling point, we would expect those incremental stress/strain relations to describe deviations from the in situ condition, which is what would be relevant in most applications.

REVIEW OF GRI PROGRAMS L. Rogers, GRI

Question (Bob Christopher, Retired): Where can and can't GRI spend money in Port Arthur?

Answer (L. Rogers, GRI): Port Arthur is an interesting project in the fact that it's been going on for several years now. One of the reasons that it is in the position it is in now is that GRI has maintained its operating procedure. I don't know that it is a hard and fast rule, if we get revenues out of the well, those revenues go into the GRI coffer directly, I can't use those on this project. So it is a practical matter. Basically, we need to coordinate a program so that the GRI moneys go into research activities and things like that and industry's moneys handle what would be more conventional activities. Probably have to get with an accountant to determine which items. In general that's the principle, that the industry people will fund the more normal development of the program and GRI's funds will go into the more technical research aspects. Then in each case we have to determine where the dividing line is. We have participated in the secondary gas and getting the new well going because we needed that sort of well to be a laboratory to do additional work. In that regard, we provide a certain amount of moneys into what would normally be conventional type work. In the Port Arthur project, GRI is providing the funds right now to do the reentrance and reestablish what the reservoir conditions are, because that is supporting the GRI goals. In the case of Port Arthur, we will not continue on and do a major test unless there's either a change in GRI policy or you get the industry people lined up to work on the project. So that's just a rough idea of the breakdown.

Question (Mason Tomson, Rice Univ.): What do you see beyond 1990?

Answer (Leo Rogers, IGT): What I see beyond 1990 is that we'll have thought of a whole lot of things to work on by that time. And a lot of activities in the co-production program will be continued. They may be continued under a different program area, however. GRI's getting some new project areas started for the more generic type work such as deep well drilling and things like that. I don't see us running out of ideas, but from project management perspective, we set out some initial goals back in 1980, and we have basically achieved our goals as they were originally written, so at that point we restructured what the next set of goals are and how we are going to get them done.

Question (Dave Riney, S-Cubed): Question - is the Sweden Project partially funded by GRI?

Answer (Leo Rogers, IGT): GRI's basic Research Department is putting a little bit of money into that project...to search for deep gas. The GRI participation is approximately 10 percent of the total program. With the 10 percent participation, we've got a couple of people that sit on advisory committees, and we are putting in our 10 percent vote, if you want to call it that. The Swedish Power Board is running that project, and they have a lot of Swedish industry people with them on that. And it is a 5,000 meter well drilling through granite. I understand they've got Parker and a consultant on the drilling, but they have not selected a drilling contractor and they are planning on doing that in the next month or so, and they have a target date sometime in May or June this year. The Swedish Power Board has a big thick book they've put out, and I have a copy of it at my desk, states that their primary objective is to get gas. They aren't too interested in proving Tommy Gold's theory about deep formed gas migrating up to provide the source. But that's fine. Tommy Gold's going around the world telling how great it is now anyway. You've probably seen some articles recently. So, GRI is supporting that to a small extent, but we are definitely not running that program.

Question (Walt Kocher, SLU): Question on Environment Impact Statement problems.

Answer (Leo Rogers, GRI): Our Environmental Project is in action again because of new funding, I can't fund everything that comes along. We did fund recently a study, which I don't know what it is...about how we got cleanup brine from brine disposal (Hitchcock)...That was conducted by the University of Houston, and a couple of graduate students came up with some interesting ways and alternate methods to clean up the brine and meet the requirements, DOE requirements primarily, and right now the operator of secondary gas is going through an assessment as to whether to drill more disposal wells or get more permits to dump additional brine into the local diversionary canal. And in our view to conduct the program, the brine handling can be a potential problem. It looks like it is more of an economics problem than just a simple engineering problem and not one we need to put a lot of research into. So we are addressing environmental issues on a case-by-base basis as they impact our particular fields. We are not addressing it as a broad generic program.

UT/BEG PROSPECT EVALUATION, LOGGING RESEARCH AND HYDROCARBON SOURCE ANALYSIS FOR N.E. HITCHCOCK — M. Light (BEG)

Question (P. Randolph, IGT): Questions on Malcolm's graph...Left side material or have a surplus of right side material? Is there a lot more eddy material on an absolute scale?

Answer (M. Light, BEG): All I can say is that this process of water washing appears to be done by very high temperature water, and it has removed the black material from the Prince well. But is also cooked, heated up, and it changes its maturity. So that's actually modified disturbance as well.

Question (Phil Randolph, IGT):...right-hand side you only have...carbon. The little blue thing over there is kind of like gasoline.

Answer (M. Light, BEG): Yes. Otherwise we look at them and we get what could very well be actual similar sands from the two wells. So you obviously look at the same statistic site but there's this remarkable change...And we think that this water washing was done by these very hot waters, and they migrated down. And we hope that when we get the analyses of the hydrocarbons done, that we are going to look at the Lindsay conservation in them and see if we can find the correlation with this mud.

Question (Phil Randolph, IGT): Pursuant to the interruption I made a little bit ago, the reason I asked that question is the Pretz well produces much more liquid hydrocarbon in relation to either water or gas than the other well.

Answer (M. Light, BEG): Yes. That, in fact, seems to be.

Question (Phil Randolph, IGT): The brine has a lot of heavy stuff added rather than light ends, and the potential for oil in relation to the other fluids?

Answer (M. Light, BEG): That's correct. It's a relationship to position in the field. As you go from the gas/water contact, the original gas/water contact, and move up the crest of the field where the Pretz well is, is almost a continuous change in the ratio of aromatic hydrocarbons. But that would not affect this particular aromatic composition, because this is a particular range...We have happened to look at that detail as well...I have made a map showing the concentrations of the gas/water ratio in the field in its direct relationship to its position.

End of morning Session of Day 2.

GAS RESEARCH INSTITUTE CO-PRODUCTION OF GAS & WATER PROGRAM

WEDNESDAY, MARCH 5, 1986

LOUISIANA STATE UNIVERSITY/GEOLOGIC SURVEY PROSPECT EVALUATION AND PROJECT INITITIATIONS WITH OPERATORS IN LOUISIANA

Z. Bassouni (LSU)

Question (Frank O'Brien, WKT): Have the people you've approached, the operators, accepted your models or have they found fault with the basic analysis that you're doing?

Answer (Z. Boussini, LSU): We have this material as an equation model. This is a tank model. Chevron, for instance, accepted as is. That is, it mirrors what they do at the division level. They didn't find any fault with it. Dick Sickle, for instance, said that's fine but we'd like to see a 3-dimensional study. Texaco, in the Dick Sickle case, we proceeded with 3-D model. So once we finish our, let's say the tank model analysis, we would work with the company to find out what their management will accept. The 3-D modeling is quite expensive, and we are trying to get the company to provide their model and if they don't want to spend this additional money, I'm happy with what we have.

EATON OPERATING COMPANY PROSPECT EVALUATION AND STATUS OF N.E. HITCHCOCK AND PORT ARTHUR PROJECTS

B. Howell, W. Parisi, L. Anderson, K. Peterson, EOC

Question (Hank Coffer EG&G): Where is the water coming from?

Answer (W. Parisi, EOC): Okay, I'll show you the aquifer map. This large boundry fault continues on south, where it hooks up with the other boundry fault, which continues east, just north of Live Oak. This fault continues up towards Banker and then there is a spur that separates Banker from this deal here. As far as I can tell, the aquifer extent goes all the way over to Tigre Lagoon. I do have some suspicions there's a large buried fault almost due north of Live Oak that runs almost north-south along the section boundary, but it does not appear to cut off the aquifer sand. We're looking at a very large reservoir, aquifer-wise anyway. So the water is coming from here and further east.

More presentation by (K. Peterson, EOC)

No questions.

More presentation (L. Anderson, EOC)

Question (?): What did you say the current gas producing rate was for Hitchcock?

Answer (L. Anderson, EOC): It is in the neighborhood of 1 and 1-1/2 million cubic feet per day, total from all the fields.

FIELD TEST RESULTS FROM N.E. HITCHCOCK

P. Randolph and T. Osif, IGT added to presentation

No questions.

MODELING RESULTS FOR N.E. HITCHCOCK K. Ancell, DF&A

No questions.

SUMMARY OF SCALE AND ADVERSE CHEMICAL REACTION RESEARCH

M. Tomson, Rice University

No questions.

SUGGESTION BY FRANK O'BRIEN

I think it would be helpful to have a meeting like this more often than every two years. I know there are budget problems, but dropping the meetings down to as infrequent as they have been, and dropping the newsletter is not a good way to get information out. I think somehow an infrequent newsletter of what's going on in the program needs to be put out by DOE or GRI, and these meetings, sure hope they can be held once a year.

Comment (L. Rogers): Good suggestion. I'll see what we can do. The one problem I have noticed through these meetings, and you may have noticed too, by the time we cover both programs in as much detail as we have today, they get to be extremely long. And we may need to work out formats to cover more material in less detail. Maybe we could do something like that and still cover these meetings just exactly like we'd like to.

III. LIST OF ATTENDEES AT MEETINGS

GEOPRESSURED INDUSTRY FORUM
MARCH 4-5, 1986
ATTENDANCE LIST

Lana Egan
EG&G Idaho, Inc.
P. O. Box 1625
Idaho Falls, ID 83415

Leo Rogers
GRI
8600 W. Bryn Mawr
Chicago, IL 60068

Charles Gilmore
USDOE
785 DOE Place
Idaho Falls, ID 83402

Raymond Fortuna
USDOE
1000 Independence Ave (FORR)
Mail Stop CE-342
Washington, DC 20585

James W. Fairchild
Dowdle Fairchild & Ancell, Inc.
14811 St. Marys #140
Houston, TX 77079

B. A. Eaton
Eaton Operating Company
1980 So. Post Oak Blvd, Suite 2000
Houston, TX 77056

Charles J. Hinrichsen
Texaco USA
P. O. Box 425
Bellaire, TX 77401

I. R. Supernan
Texaco Inc.
P. O. Box 425
Bellaire, TX 77401

J. A. Rodgers
Retired
2214 Cherry Bend
Houston, TX 77077

Evan Hughes
Electric Power Research Institute
P. O. Box 10412
Palo Alto, CA 94303

Charles Byrer
Unconventional Gas Projects
USDOE
Morgantown Energy Technology Center
P. O. Box 880
Morgantown, WV 26505

R. W. (Bob) Christopher
Retired
910 Doral Lane
Houston, TX 77073

Virginia R. Van Sickle
Louisiana Geological Survey
P. O. Gox G
University Station
Baton Rouge, LA 70893

C. G. Groat
Louisiana Geological Survey
P. O. Gox G
University Station
Baton Rouge, LA 70893

Terry Osif
IGT
3424 S. State Street
Chicago, IL 60616

David Von Bargen
Texas Eastern Trans.
P. O. Box 2521
Houston, TX 77252

Dean F. Keeley
University of Southwestern Louisiana
P. O. Box 44250, USL
Lafayette, LA 70504

Philip L. Randolph
IGT
3424 S. State Street
Chicago, IL 60616

Walt Kocher
Southern University
Department of Civil Engineering
Baton Rouge, LA 70814

GEOPRESSURED INDUSTRY FORUM
MARCH 4-5, 1986
ATTENDANCE LIST

Dru Trahan
LA Geological Survey
LA State University
P. O. Box G
Baton Rouge, LA 70893

Don Stevenson
LA Geological Survey
LA State University
P. O. Box G
Baton Rouge, LA 70893

Curtis McDonald
Department of Chemistry
Texas Southern University
Houston, TX 77004

G. Sethuraman
Department of Chemistry
Texas Southern University
Houston, TX 77004

P. C. Sundareswaran
Environmental Science & Engineering Dept.
Rice University
P. O. Box 1892
Houston, TX 77251

Mason Tomson
Environmental Science & Engineering Dept.
Rice University
P. O. Box 1892
Houston, TX 77251

David Bohanan
2600 E. Wardlow Road
Long Beach, CA 90805

R. E. McCluskey, Jr.
Amoco Production Co.
P. O. Box 3385
Tulsa, OK 74102

Robert C. Shopland
RCS Geotechnical
11522 Bellerive Drive
Houston, TX 77072

Frank D. O'Brien
WKT
9777 Harwin Drive, Suite 408
Houston, TX 77036

Susan M. Prestwich
DOE-Idaho
785 DOE Place
Idaho Falls, ID 83401

Jack Ramsthaler
EG&G Idaho, Inc.
P. O. Box 1625
Idaho Falls, ID 83415

T. David Riney
S-Cubed
P. O. Box 1620
LaJolla, CA 92038

David B. Lombard
USDOE
Mail Stop CE-34
Washington, DC 20585

J. Donald Clark
Consulting Petroleum Engineer
5959 West Loop South
Suite 232
Bellaire, TX 77401

Malcolm P. R. Light
Bureau of Economic Geology
University of Texas at Austin
University Station, Box X
Austin, TX 78713

Tom Meahl
Eaton Operating Co.
1980 Post Oak Blvd., Suite 2000
Houston, TX 77056

Chris Hayden
Institute of Gas Technology
3424 S. State Street
Chicago, IL 60616

Margaret W. Hare
Dresser Mugcobar
Houston, TX
750-3781

W. F. Ellis
Consultant
5203 Verdont Way
Houston, TX 77069

GEOPRESSURED INDUSTRY FORUM
MARCH 4-5, 1986
ATTENDANCE LIST

O. Angeli
Gruy Petroleum Mgmt. Co.
2500 Tanglewilde, Suite 150
Houston, TX 77063

M. Dorfman
University of Texas, CPE 2.5
Austin, TX 78712

John R. Meriwether
University of Southwestern Louisiana
P. O. Box 44210
Lafayette, LA 70504

Don Lapin
University of Houston CIVE
Houston, TX 77004

Eric Fahrenthold
Department of Mechanical Engineering
University of Texas
Austin, TX 79712

K. L. Ancell
DF&S
14811 St. Marys
Houston, TX 77079

Z. Bassiouni
Louisiana State University
Baton Rouge, LA 70803

Bob Howell
Eaton Industries
1980 Post Oak Blvd., Suite 2000
Houston, TX 77056

Lonnie L. Anderson
Bill Parisi
Kim Peterson
Eaton Industries
1980 Post Oak Blvd., Suite 2000
Houston, TX 77056

Fred L. Goldsberry
Zapata Exploration Co.
P. O. Box 4240
Houston, TX 77210

IV. APPENDIXES

A. APPENDIX 1

GEOPRESSURED-GEOTHERMAL REVIEW

S. PRESTWICH - DOE-ID

Geopressure Geothermal Program

- Objective
- Well test program
- Supporting research program
- Long range plan

6 6714

Geopressure Geothermal Program

FY-85 Accomplishments

- Gladys McCall well maintained at 95% flow efficiency
- Downhole scale inhibitor injection procedure successfully completed
  — Joint effort GRI, Rice University, and DOE
  — Flow increased 15 -- 30,000 B/D
- New well operating contractor selected
- Determined existing analytical techniques do not predict reservoir performance

6 6719

Geopressured Geothermal Program

FY-86 Plan

- Continue flow testing Gladys McCall
- Rework Pleasant Bayou
- Install EPRI System
- Initiate flow testing at Pleasant Bayou
- Focus research program on reservoir analysis problem

6 6720

Gladys McCall Flow Testing

- Continue flow testing at high rate
- Evaluate alternate "pill" injection procedures
- Obtain controlled downhole data for reservoir evaluation
- Assess corrosion
- Monitor for unexpected problems

6 6725

Gladys McCall Shutdown

- Surface Facilities
  — Minor pipe replacements and valve repairs
- Injection Well
  — Tubing parted at 2100 ft still useable
- Bottom Hole Fill
  — Suspect leak
- Production Well Tubing
  — Good condition
- Pill Injection
  — Revised procedure successful
- Reservior Recovery
  — Consistent with prior data
- Current Status
  — 30,000 + Bbls/D

6 6724

Pleasant Bayou Test Plan

- Clean production well, determine reservoir pressure
- Retube production well
- Repair injection well
- Install EPRI Hybrid Electric Power Generation System
- Repair surface facilities
- Initiate flow at high rate and test EPRI System

6 6721

Geopressured Geothermal Program

Areas of Research

- Determine magnitude resource
- Develop exploratory techniques
- Assess production problems
- Verify utilization technology

6 6726

Geopressured Geothermal Program FY-86 Supporting Research

Priority	Research Tasks
(1) Reservoir analysis	— Rock mechanics — Geology — Oil analysis — Modeling and data analysis
(2) Environmental monitoring	— Subsidence — Seismicity — Water quality
(3) Resource prediction	— Mud log analysis — Effect rock stress on core resistance — Trace element effect on neutron logs
(4) Scale inhibition	— Cooperative effort with GRI on inhibition chemistry

6 6715

Geopressured Geothermal Program Supporting Research

University of Texas

- Technical support
- Logging research
- Information system
- Acquifier simulation
- Rock mechanics

6 6716

Geopressured Geothermal Program
Supporting Research

Louisiana State University

- Subsidence studies
- Seismic studies
- Geology studies Gladys McCall

6 6717

Geopressured Geothermal Program
Supporting Research

- SCUBED
  - — Reservoir modeling
- University Southwestern Louisiana
  - — Sampling and analysis gas condensates and oil
- Lawrence Berkeley Lab
  - — Theoretical analysis gas condensates and oil
- Southern University
  - — Water quality monitoring
- Texas Southern
  - — Cooperative research with Rice University scale inhibitors
- NOAA
  - — Leveling survey Louisiana

6 6718

Geopressured Geothermal Program

Five-Year Plan

FY-86	Operate Gladys McCall* and Pleasant Bayou well systems
FY-87	Continue operation of Wells* and evaluate Hulin condition
FY-88	Continue operations*, rework Hulin well, install advanced energy conversion system on Hulin well
FY-89	Operate wells*
FY-90	P&A wells complete reports

*Well testing on each well will continue until operating costs exceed revenue. Only one well can operate at a loss.

6 6722

Goepressure Geothermal Program

Problem - Budget cost 5m/yr → $3\bar{m}/\bar{yr}$

Potential areas to delay

- Well testing
  - — Gladys McCall
  - — Pleasant Bayou
  - — Hulin

- Supporting research
  - — Reservoir analysis
  - — Environmental analysis
  - — Resource analysis
  - — Scale studies

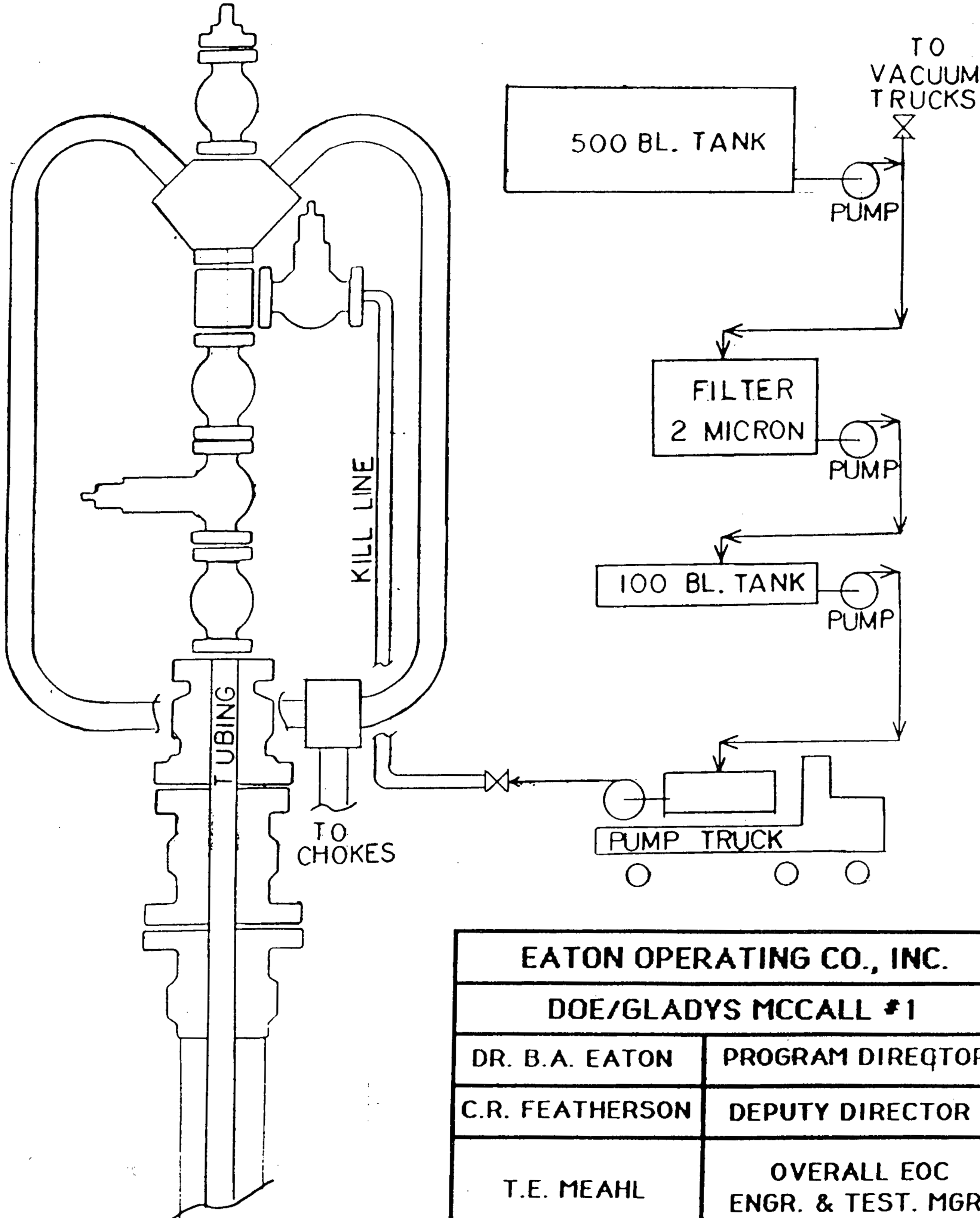
- Utilization studies
  - — EPRI
  - — Advanced system

6 6713

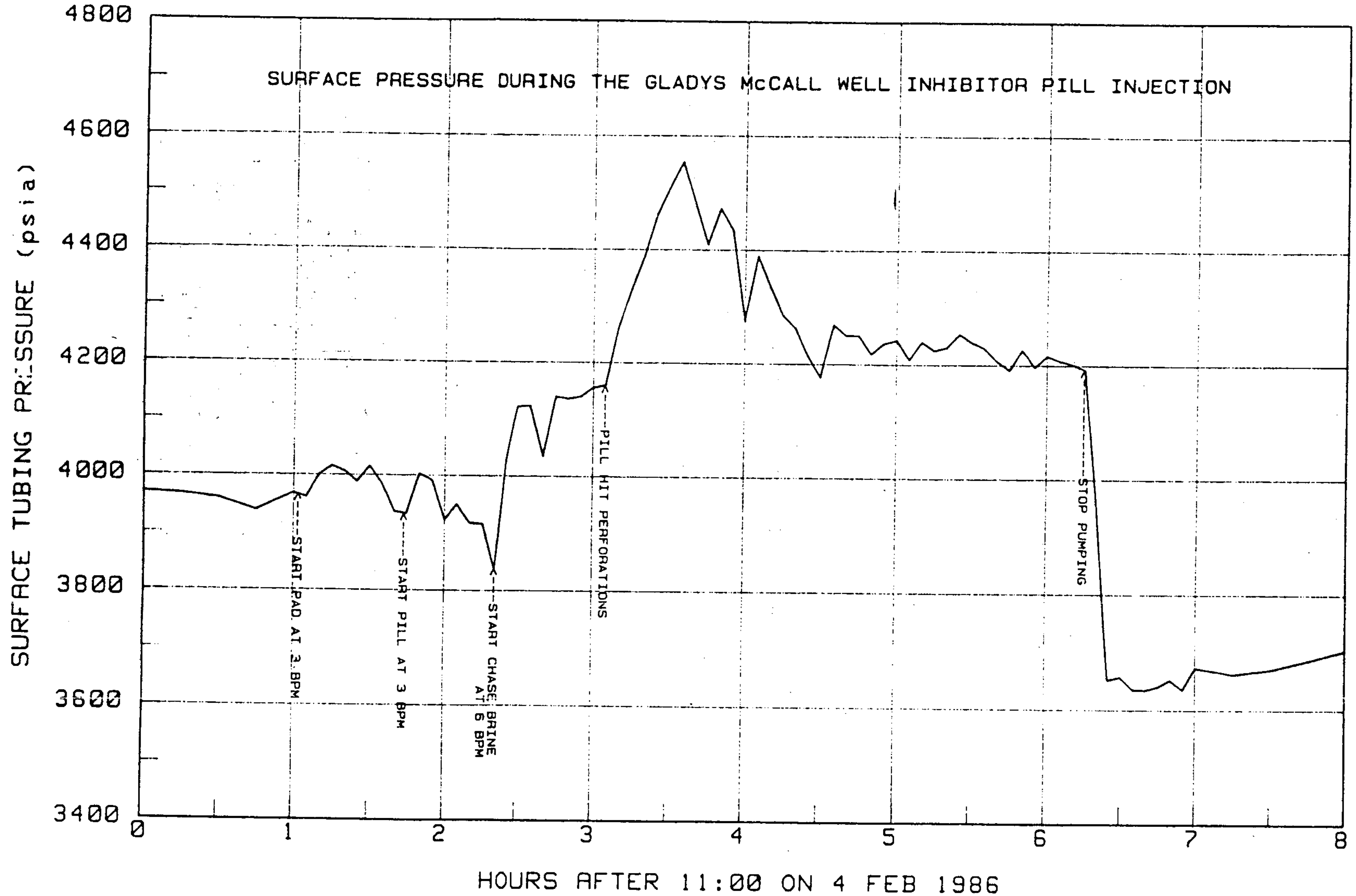
B. APPENDIX 2

WORKOVER OF GLADYS McCALL INCLUDING PILL TREATMENT

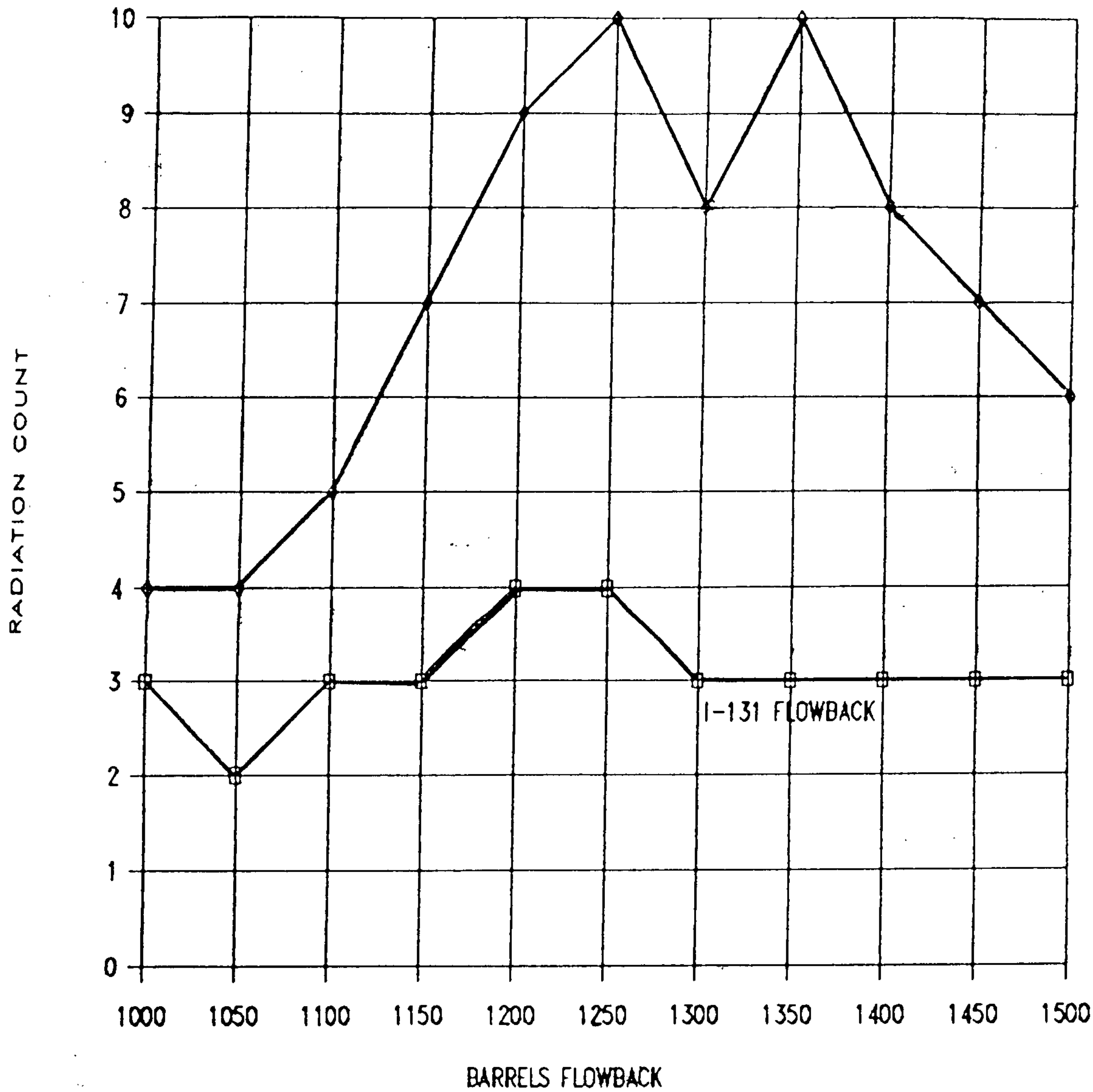
T. MEAHL - EOC



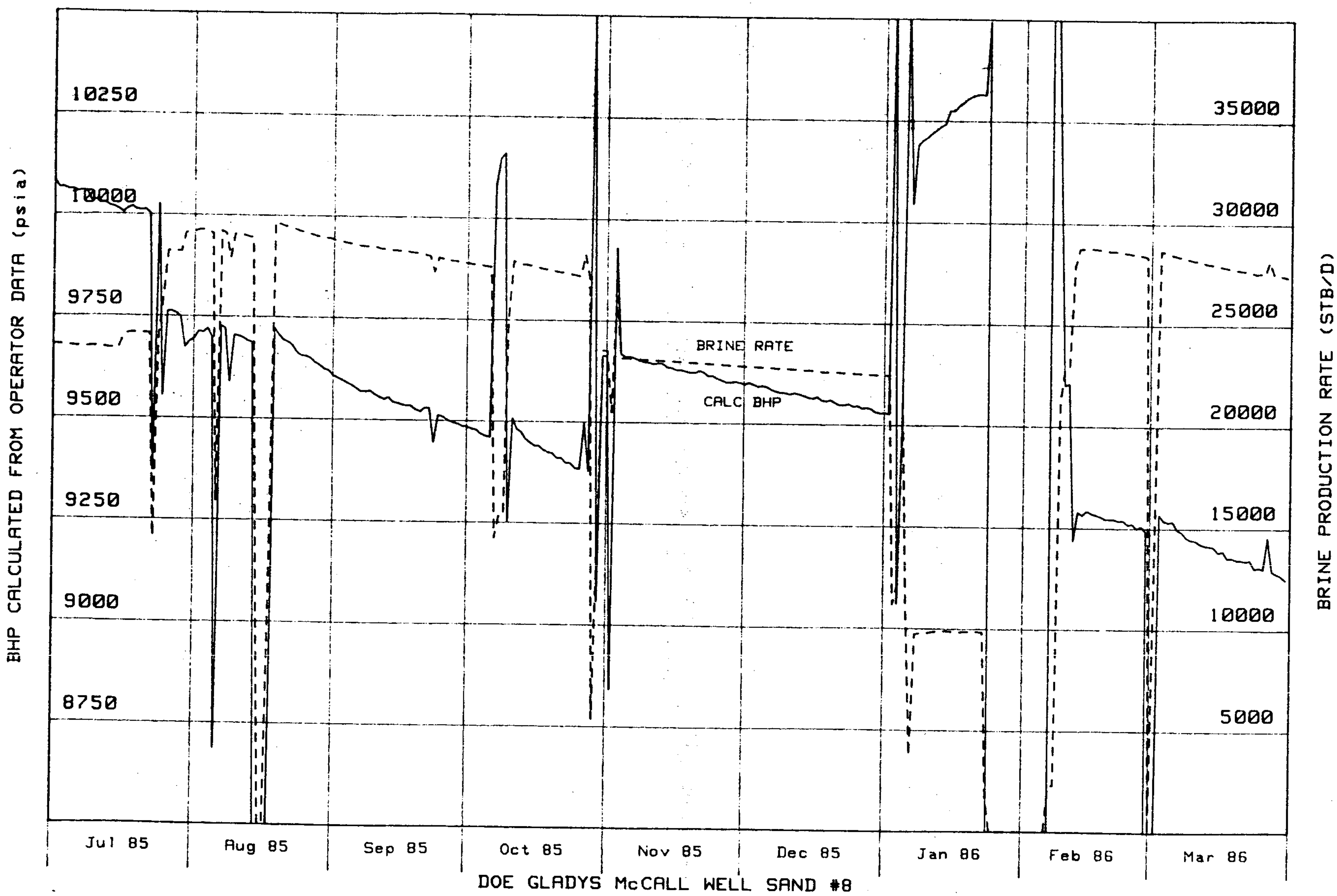
EATON OPERATING CO., INC.	
DOE/GLADYS MCCALL #1	
DR. B.A. EATON	PROGRAM DIRECTOR
C.R. FEATHERSON	DEPUTY DIRECTOR
T.E. MEAHL	OVERALL EOC ENGR. & TEST. MGR.
PILL TREATMENT	



SURFACE PRESSURE DURING THE GLADYS McCALL WELL INHIBITOR PILL INJECTION
SURFACE TUBING PRESSURE (psia)
HOURS AFTER 11:00 ON 4 FEB 1986
4800
4600
4400
4200
4000
3800
3600
3400
0
1
2
3
4
5
6
7
8
START PAD AT 3 BPM
START PILL AT 3 BPM
START CHASE BRINE AT 6 BPM
PILL HIT PERFORATIONS
STOP PUMPING



EATON OPERATING CO., INC.	
DOE/GLADYS MCCALL #1	
DR. B.A. EATON	PROGRAM DIRECTOR
C.R. FEATHERSON	DEPUTY DIRECTOR
T.E. MEAHL	OVERALL EOC ENGR. & TEST. MGR.
PILL TREATMENT	


BHP CALCULATED FROM OPERATOR DATA (psia)
BRINE PRODUCTION RATE (STB/D)
10250
10000
9750
9500
9250
9000
8750
35000
30000
25000
20000
15000
10000
5000
BRINE RATE
CALC BHP
Jul 85
Aug 85
Sep 85
Oct 85
Nov 85
Dec 85
Jan 86
Feb 86
Mar 86
DOE GLADYS McCALL WELL SAND #8

C. APPENDIX 3

SCALE INHIBITION AT GLADYS McCALL-SUMMARY AND REVIEW

M. TOMSON - RICE UNIVERSITY

SUMMARY OF GLADYS McCALL INHIBITOR SQUEEZE

Progress has been made toward controlling scale formation from brines often associated with geopressured energy production and with coproduction wells. As brine flows out of the formation and up the well the pressure drops. The pressure drop causes dissolved carbon dioxide, CO_2, to go out of solution, which increases the solution pH. The pH rise causes aqueous bicarbonate, HCO_3, to be converted to carbonate, $CO_3(2-)$, which tends to initiate calcium carbonate, $CaCO_3$, precipitation either in the formation pore throats near the well bore or on the production tubing wall. The tendency of brine to form scale decreases as the temperature drops. The drop in temperature is rarely sufficient to offset the pressure drop. If the tubing is scale free and the ratio of the bottom hole to the surface pressure is less than about 6 to 10, generally scale formation will not commence, but this severely limits the production rate. Alternatively, trace concentrations of chemicals which inhibit scale formation can be used. Most scale inhibitors are either phosphonates, polyacrylates, or polymaleates and generally prevent scale formation at concentrations of 1 mg/l or less. These inhibitors can be injected in the surface equipment or downhole with a small treating string or can be squeezed into the formation for slow release on flowback.

To prevent scale formation in the surface equipment, inhibitors can be injected immediately after the christmas tree. In most cases this is an inexpensive and efficient process. If the pressure of the hot brine is dropped to atmospheric in the surface equipment, it will generally not be possible to prevent nucleation and scale formation with any reasonable concentration of inhibitors. (Note that in such cases it may be possible to prevent scale formation by reducing the temperature before the final pressure drops to atmospheric pressure, but to the author's knowledge such a procedure has not been tried.)

To prevent scale formation in the production tubing as well as in the surface equipment, inhibitors can be injected downhole via a small diameter, (1/4 in. OD, or less) tubing. Special alloy steels are generally required because most inhibitors are acidic and contain small amounts of chloride which promotes corrosion.

The majority of the research in the present report has related to inhibitor squeeze methods. An inhibitor squeeze can potentially prevent scale formation in the formation, the production tubing, and the surface equipment. The technology of squeezing inhibitors into formations which are calcite cemented is rather well developed. In summary, an appropriate amount of the acid form of an inhibitor is injected into the formation and reacts with the calcite to dissolve calcium and neutralize the acid, at the same time. The neutralized calcium-inhibitor salt precipitates in place. Then, as brine flows back through the formation a small amount of the calcium-inhibitor salt dissolves slowly releasing inhibitor into solution. Such an inhibitor squeeze into the Prets well in the Hitchcock Field, near Houston, TX, effectively prevented scale formation for six to nine months. This is a longer treatment life than is normally reported in the industry, but it is not unreasonable. Samples of the brine were periodically collected and analyzed for inhibitor concentration. The concentration of inhibitor dropped to about 0.5 to 1.0 mg/l within a week and remained in that range for a long period of time. Some difficulty was encountered with the analytical measurement of the inhibitor concentration when it was less than 0.5 mg/l. Consequently, it is not known how low the inhibitor concentration was when scale began to form. Since that time, an improved method of inhibitor separation and measurement has been developed which permits accurate measurements of phosphate or phosphonate based inhibitor concentrations to as little as 0.02 mg/l.

When formations are secondary quartz cemented, as is the DOE geopressured Gladys McCall well, and a normal inhibitor squeeze is attempted, generally insufficient amounts of the inhibitor is retained by the formation to be cost effective. It is, therefore, necessary to induce precipitation of the inhibitor by either using a calcium chloride overflush, adding calcium to the pH adjusted inhibitor solution, or, as suggested herein, to use the calcium in the formation brine itself. Several laboratory column simulations of the squeeze regime were tested using Gladys McCall core material. In these laboratory tests, about five times as much inhibitor was retained by the core materials when a calcium chloride overflush was used. As a consequence, an inhibitor pill we designed to be injected at about two barrels per minute in the following sequence:

1. 300 B of 15% NaCl spacer

2. 100 B of 6% inhibitor in 15% NaCl (the inhibitor was nitrilotri (methylene phosphonic) acid from Champion Chemicals of Houston, TX)

3. 100 B of 15% NaCl spacer

4. 100 B of 10% $CaCl_2$ overflush

5. 500 B of 15% NaCl into the formation as a pusher

6. The well was to be shut in for 24 hours to allow reaction

Due to pressure increase when the calcium chloride came in contact with the formation, it was only possible to pump the $CaCl_2$ and about 25 B of the next NaCl before the well was shut in to permit reaction. Brine samples were taken every 10 B during the flow back of the pill and periodically thereafter. These samples were analyzed for numerous elements, in addition to the inhibitor itself. It was found that magnesium was the most distinctive tracer for the formation brine and that sodium and potassium could probably be used to trace the pill. The three hundred barrels of lead spacer could never be identified by any of the tracers in the samples; an explanation for its fate is still not available. About 70% of the inhibitor flowed back with the first few thousand barrels of brine production. The remaining inhibitor was slowly released over the next six months. The concentration of the inhibitor dropped to about 0.1 to 0.2 mg/l within a few weeks and remained there until the well was shut in for repair and resqueeze in January, 1986. Prior to the inhibitor squeeze, the production was limited to about 15,000 BPD in order to avoid scale formation. This severely curtailed gas production. After the squeeze it was possible to increase the production rate to about 30,000 BPD, still without scale formation in the production tubing. At about three months into production a light scale was observed in the surface equipment in the final filters before the disposal well. This was prevented by addition of 0.25 mg/l of inhibitor. Still no indication of scale formation in the production tubing was found, and when the well was shut in the high pressure side of the choke was observed to be scale free.

Based upon an analysis of the breakthrough data of the flowback curves from the first squeeze job, it was estimated that it should be possible to use the calcium in the formation brine if sufficient mixing could be induced by a large pill. This would avoid the pressure increase observed when the calcium of the overflush hit the formation and would greatly simplify the overall operation of the pill application. Such a pill was designed and tested in January, 1986. At present all indications are that it should be possible to use the formation calcium as a source of calcium to precipitate the calcium-inhibitor salt, but the flow back data is still being analyzed and will be reported in a future presentation and report.

Mason Tomson

OUTLINE

SCALE AND CORROSION CONTROL
PROJECT REVIEW
MARCH 4 AND 5, 1986

I. INTRODUCTION AND STATEMENT OF PROBLEM
II. SATURATION INDEX - SI
III. INHIBITORS
IV. SAMPLING AND KIT
V. HITCHCOCK WELLS**
VI. GLADYS MCCALL AND PLEASANT BAYOU NO. 2
VII. RELATED PROJECTS
VIII. PRESENT PROBLEMS AND APPROACHES TO SOLUTIONS

*MASON TOMSON - PRINCIPAL INVESTIGATOR
**P.C. SUNDARESWARAN(SUNDAR) - RESEARCH ASSOCIATE

QUESTION: IF SCALE DOES FORM IN TUBING, HOW FAST MIGHT IT FORM?

MAKE THE FOLLOWING ASSUMPTIONS:

1. 5000 BPD; 212^{0}F; 2.5 IN ID TUBING; DENSITY = 1.00 G/CM^3; 100 FT. AT TOP IS SCALING; SINGLE PHASE LAMINAR FLOW; 700 MG/L T_{CA} IN BRINE.

2. REACTION IS MASS TRANSPORT LIMITED AND IS AT STEADY STATE.

$$LN \frac{C_{IN}}{C_{OUT}} = \frac{A_{KM}}{Q} = 0.034 \text{ OR}$$

$C_{OUT} = C_{IN}/1.03$ OR 3% OF T_{CA} PRECIPITATES.

K_M = 0.005 CM/SEC. MASS TRANSPORT CONSTANT FROM SIEDER AND TATE FORMULA

$$= 1.86 \times (RE)^{1/3}\ (SC)^{1/3}\ (D/L)^{1/3}\ D/D$$

A = AREA OF PIPE
Q = FLOW RATE
RE, SE = REYNOLDS, SCHMIDT NUMBERS
D,L = TUBING DIAMETER AND LENGTH
D = MOLECULAR DIFFUSION COEFFICIENT AT T.

AT END OF 2 WEEKS:

1.0 IN 0.3 IN	123 LBS $CACO_3$/100 FT.
RADIUS	723 GAL OF 15% HCL
	\$700/2 WEEKS OR \$18,200/YEAR
	VS: (2-4) INH. SQUEEZES/YR @ \$10,000/EACH

SCALING AND ITS REMOVAL OR PREVENTION IN THE HITCHCOCK FIELD
(PRETS, DELEE AND THOMPSON TRUSTEE WELLS)

A. STATEMENT OF PROBLEM

B. LABORATORY STUDIES - SIMULATION OF INHIBITOR SQUEEZE

C. CALCULATIONS - ΔSI AT DIFFERENT DEPTHS

D. APPROACHES TO SOLUTION

   1. INHIBITOR SQUEEZE

   2. ACIDIZING EVERY TWO WEEKS

E. RELATIVE ECONOMICS OF THE TWO PROCEDURES

F. SUGGESTED APPROACH TO PRESENT AND FUTURE WORK

A. STATEMENT OF PROBLEM

1. PRODUCTION OF NATURAL GAS FROM GEOPRESSURED WELLS ASSOCIATED WITH PRODUCTION OF LARGE QUANTITIES OF BRINE.

2. CHLORIDE (CL^-), SODIUM (NA^+), CALCIUM (CA^{+2}) AND BICARBONATE (HCO_3^-) MAJOR CONSTITUENTS OF BRINE.

3. METHANE (CH_4) AND CARBON DIOXIDE (CO_2) CONSTITUTE THE GAS PHASE.

1. AS CO_2 FLOWS OUT OF THE WELL ITS CONCENTRATION IN SOLUTION DECREASES WHICH RAISES THE PH.

2. HIGHER PH CAUSES HCO_3 TO BE CONVERTED CARBONATE, CO_3 $^{-2}$ WHICH INCREASES CHANCES FOR SCALE FORMATION.

B. LABORATORY STUDIES - SIMULATION OF INHIBITOR SQUEEZE

SCALE FORMATION CAN BE PREVENTED BY USE OF INHIBITORS TO INTERACT WITH NUCLEI THEREBY PREVENTING IT FROM FORMING $CACO_3$ SCALE.

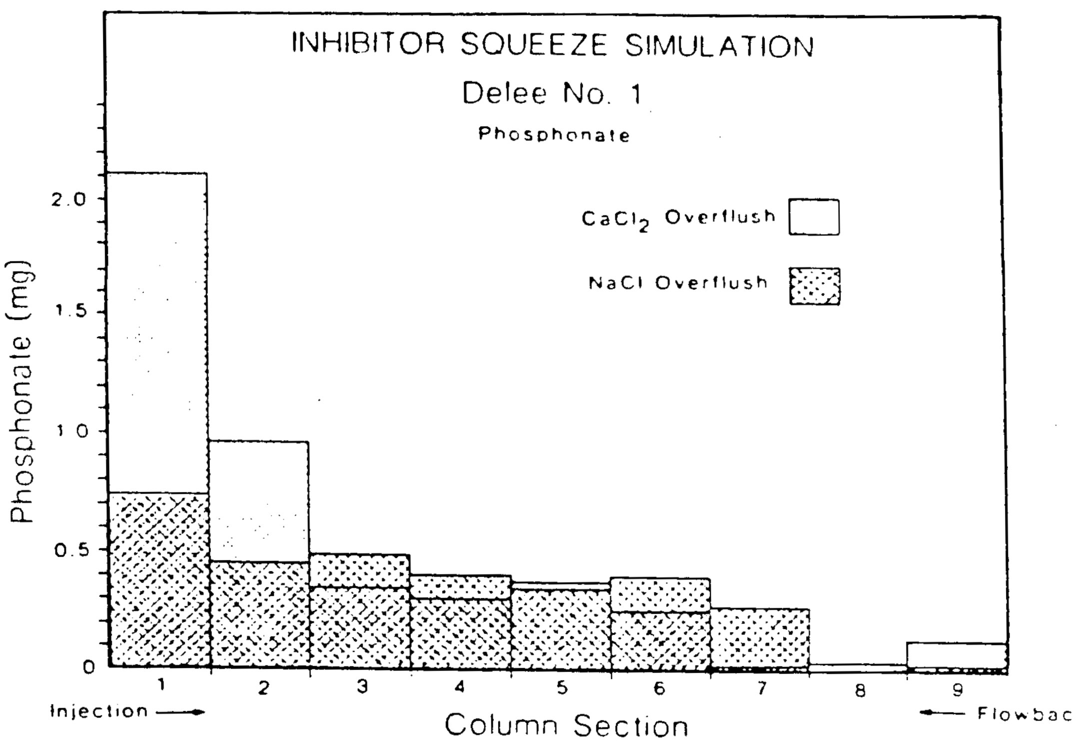


Figure 9-3. Inhibitor squeeze simulation in rock from Delee No. 1 well using Gyptron T-132 phosphonate. The effect of $CaCl_2$ overflush is not large; this is because there is some calcium present in the rock.

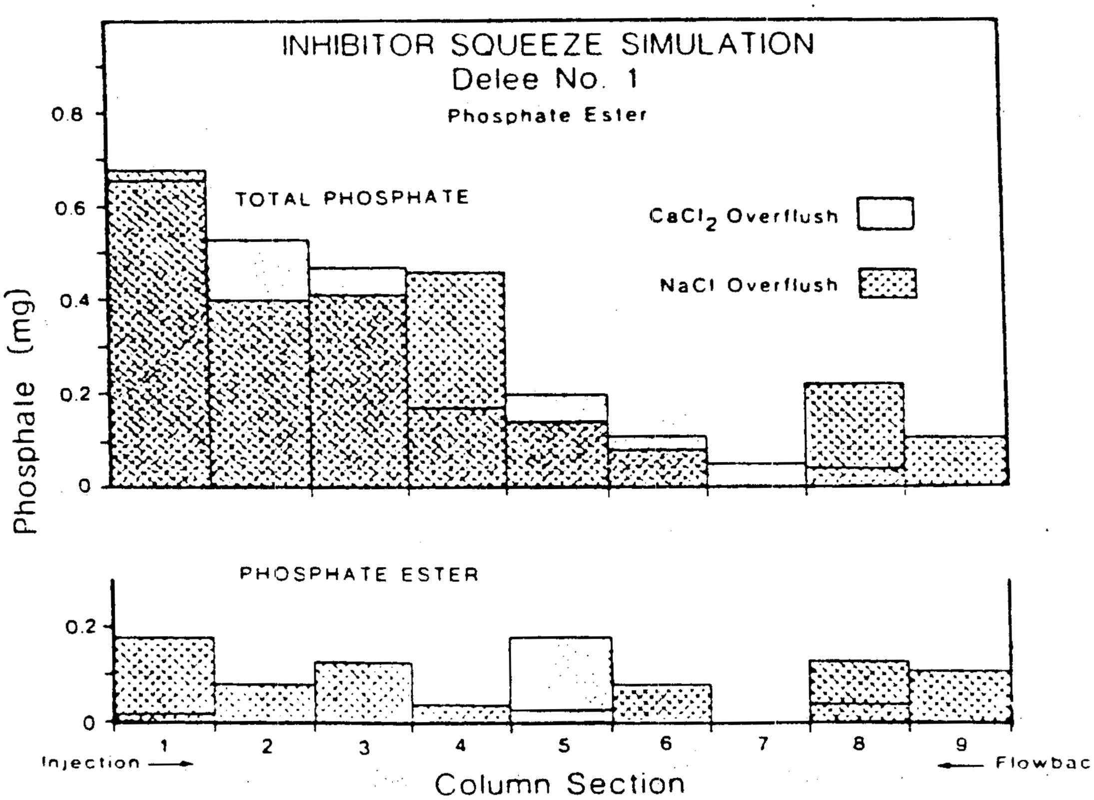


Figure 9-4. Inhibitor squeeze simulation in rock from the Delee No. 1 well using Nutro S-21 Phosphate Ester/Phosphate inhibitor. The effect of $CaCl_2$ is negligible. Most of the residual inhibitor present is as phosphate indicating decomposition of the phosphate ester.

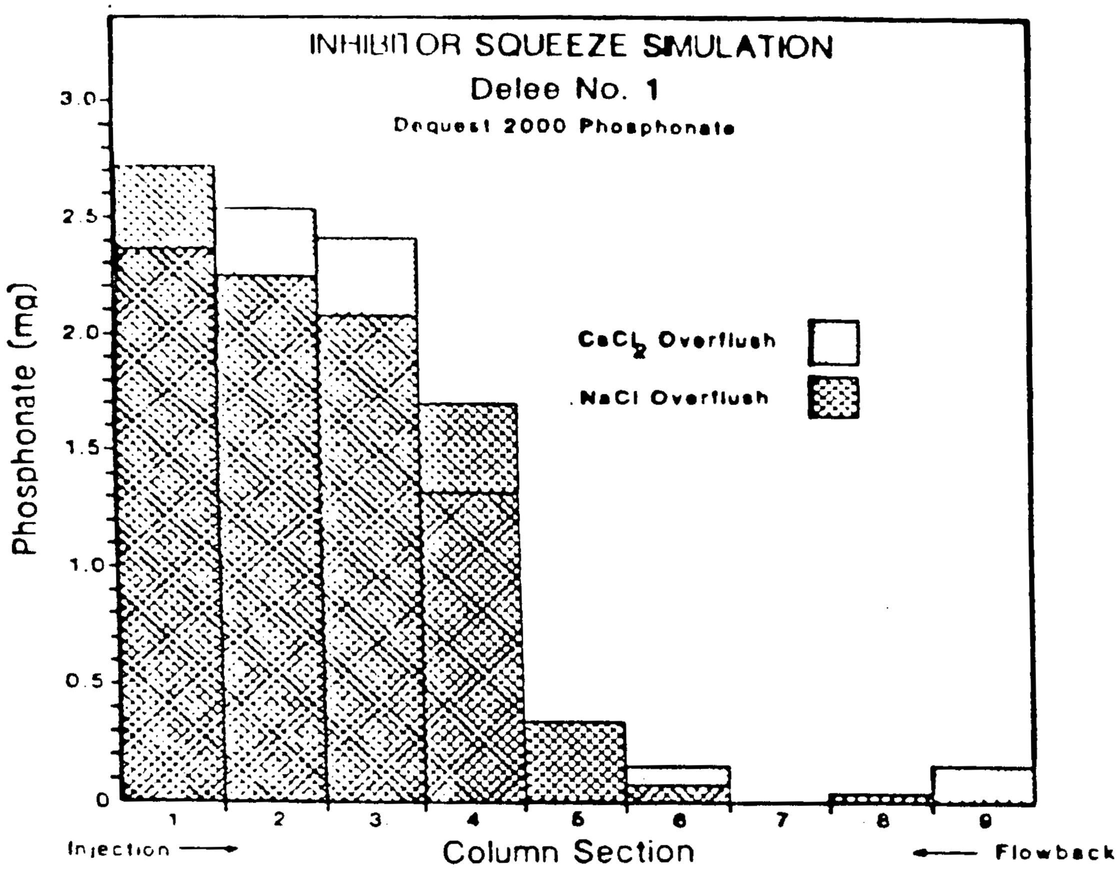
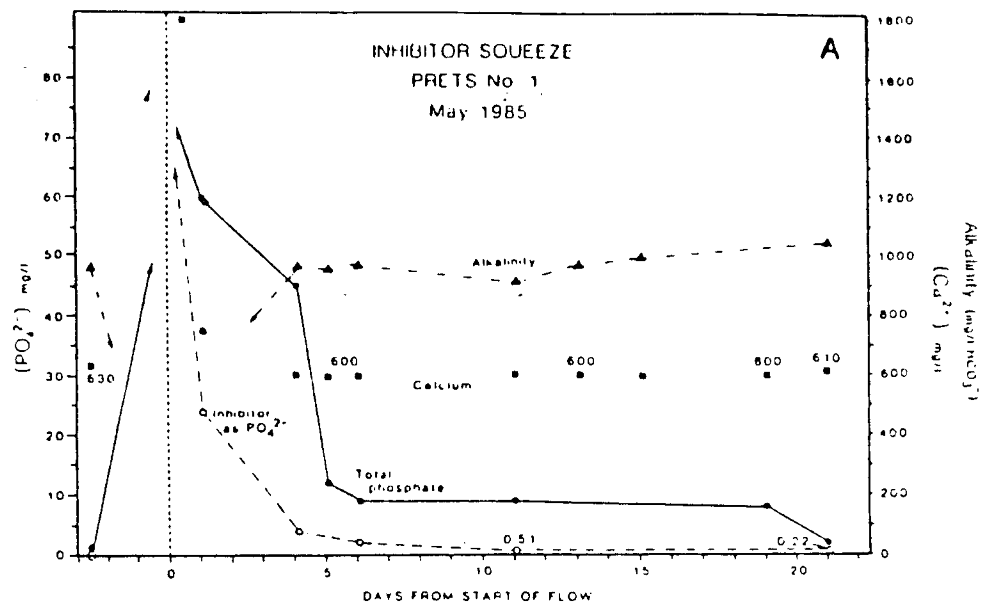


Figure 9-5. Inhibitor squeeze simulation in rock from Delee No. 1 well using Dequest 2000 phosphonate. The effect of $CaCl_3$ overflush is not significantly different than the NaCl overflush, due to the presence of calcium in the rock.

TABLE 5-8. CHANGE IN SATURATION INDEX (ΔSI) VS T, P AND DEPTH FOR PRETS WELL

Depth ft	T °F	P psi	ΔSI
0.	195.	125.	1.481
68.	195.	150.	1.400
141.	195.	175.	1.332
215.	195.	200.	1.272
291.	196.	225.	1.233
367.	196.	250.	1.185
443.	196.	275.	1.142
519.	196.	300.	1.102
595.	196.	325.	1.065
670.	196.	350.	1.031
746	197.	375.	1.013
820.	197.	400.	.983
1116.	197.	500	.879
1405.	198.	600.	.806
1689.	199.	700.	.746
1843.	199.	755.	.709
2119.	199.	855.	.647
2391.	200.	955.	.606
2659.	201.	1055.	.569
3182.	202.	1255.	.492
3691.	203.	1455.	.427
4189.	204.	1655.	.370
4677.	205.	1855.	.319
5156.	206.	2055.	.274
5628.	207.	2255.	.232
6093.	208.	2455.	.194
6555.	209.	2655.	.159
7017.	210.	2855.	.126
7474.	211.	3055.	.096
7928.	212.	3255.	.067
8379.	212.	3455.	.026
8827.	213.	3655.	.000
8990.	214.	3728.	.000

a small injection tubing into the well at one to two thousand feet and inject inhibitor. This would possibly prevent all scale in the tubing and the surface equipment, if all the analyses are correct. As can be seen from data in Table 5-7, scaling does not occur as much at 1000-2000 ft as between the surface and 1000 ft.



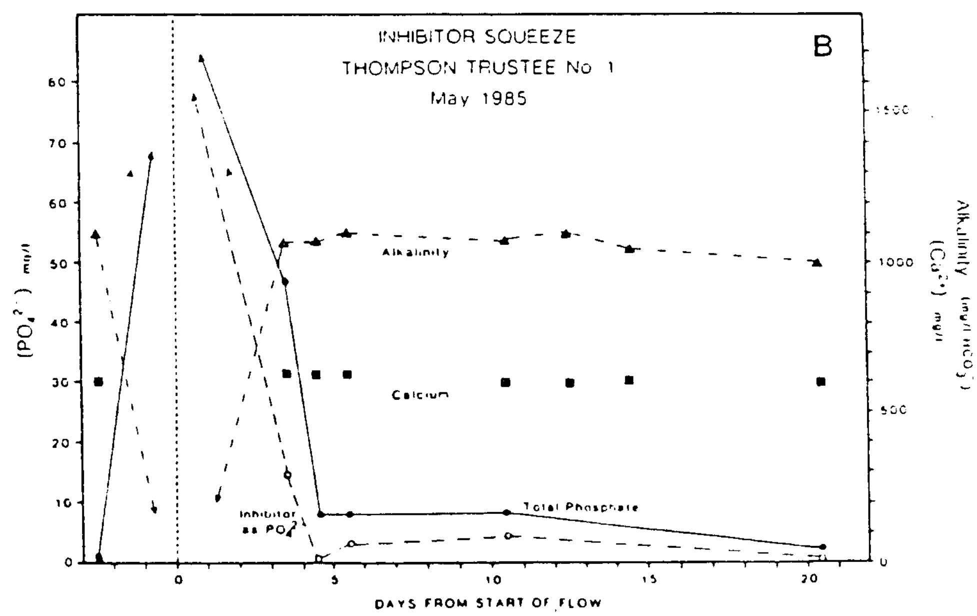


Figure 5-5. Effect of inhibitor squeeze on brine chemistry at two Hitchcock Field wells. A = Prets No. 1; B = Thompson Trustee No. 1. Samples were taken the day before the wells were cleaned with acid, squeezed with a Phosphate Ester inhibitor (Nutro Su21), and shut in for about two days. Most of the inhibitor appears to have decomposed to orthophosphate.

TABLE 2

Analysis of Samples Taken During Acidizing At Prets #1 On
January 20, 1986

Normality of 15% HCl used = 4.66

Sample	Ca M	Fe M	Acidity N	Total N*
1	0.02	0.0006	0.006	0.0472
2	0.05	0.0114	0.022	0.145
3	0.40	0.16	0.13	0.45
4	1.62	0.207	0.48	4.13
5	1.50	0.23	0.58	4.04
6	1.76	0.23	0.50	4.47
7	1.66	0.235	0.46	4.25
8	1.60	0.36	0.52	4.44
9	1.67	0.29	0.48	4.40
10	0.085	0.0125	0.30	0.495
11	0.023	0.00076	0.012	0.0595
12	0.62	0.128	0.26	1.757
13	0.77	0.130	0.26	2.061
14	0.64	0.171	0.38	2.003
15	0.72	0.173	0.30	2.086
16	0.81	0.191	0.42	2.422
17	1.57	0.243	0.62	4.246
18	1.50	0.243	0.63	4.116
19	1.43	0.214	0.66	3.949
20	0.50	0.109	0.31	1.528
21	0.01	0.0014	0.036	0.059
22	0.01	0.004	0.012	0.0329

*Total N = 2(Ca,M) + 2(Fe,M) + Acidity, N

E. RELATIVE ECONOMICS OF THE TWO PROCEDURES

1. INHIBITOR SQUEEZE - FOUR JOBS PER YEAR AT $10,000-$15,000; EACH JOB - $40,000-$60,000 A YEAR.

2. ACIDIZING - ABOUT $700-$1000 EACH JOB EVERY TWO WEEKS; $18,000-$26,000 A YEAR.

F. SUGGESTED APPROACH TO PRESENT AND FUTURE WORK

1. ADJUST PRODUCTION PARAMETERS TO AVOID SCALE.

2. LARGER PRODUCTION TUBING TO AVOID PRESSURE DROP DUE TO FRICTIONAL LOSSES.

3. PERIODICALLY REMOVE SCALE WITH CORROSION INHIBITED 15% HYDROCHLORIC ACID.

4. SQUEEZE SCALE INHIBITOR INTO FORMATION.

5. USE DOWN HOLE TREAT STRING TO INJECT SCALE INHIBITORS JUST ABOVE THE PACKER.

5. FIELD STUDIES

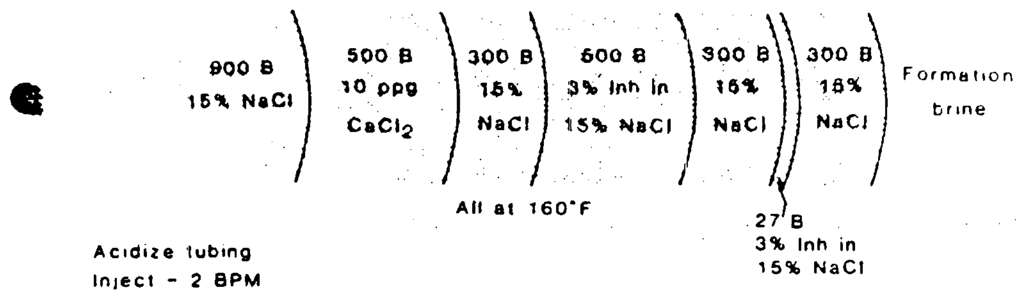
5.1 GLADYS MCCALL WELL

Samples were collected from the well using the new collection techniques: brine is flowed through a coil of tubing in an ice bath to cool it and bubbled with 100% CO_2 as it is collected. These samples with no inhibitor added remain stable if stored in a refrigerator. These stabilized samples will be used in laboratory studies.

5.1.1 INHIBITOR SQUEEZE

An inhibitor squeeze was attempted at the Gladys McCall No. 1 well in May. It was not successful because the pill fluids could not be pumped into the formation. The details of this procedure are outlined in Figure 5-1. It is believed that the formation of calcium-inhibitor salts and/or iron oxides downhole or in the surface storage tanks caused the problems. These particulates formed due to contaminated fluids used to prepare the pill. Some useful information was obtained from this failed test, however, as outlined in Figure 5-1. The size of the mixing front between the pill and the formation brine was estimated from the salinity data (Figure 5-2), which clearly shows the transition from 150,000 mg/l salinity in the pill to 100,000 mg/l in the formation brine. The zone of mixing was determined to be about 100 barrels for this small pill. From this data the formation dispersivity was determined by numerical simulation to be about 0.1 ft. The phosphonate data (Figure 5.2) is much as expected: a large portion of the injected inhibitor returns almost immediately, followed by a period of lower levels of inhibitor for a longer period of time.

1. Plan



Acidize tubing
Inject - 2 BPM
Shut in 24 hrs.
Flow - 4000 BPD - 2 days
Flow - 25,000 BPD

2. Results

1. Found 400 ppm Ca & 8 ppm Fe in brine
2. 300 B NaCl injected, little resistance
3. 27 B pill injected, produced large resistance to pumping
4. Flow - 12,000 BPD for 8 hrs.
5. 6% pill tried, turbid : discarded
6. Another 25 B 6% pill prepared, OK
7. 100 B NaCl spacer injected with considerable resistance
8. 25 B pill injected, resistance
9. Shut in for 24 hrs.
10. Flow at 4000 BPD for 48 hrs.
11. Flow at 15,000 BPD
12. New pill planned

3. Conclusions

1. Mixing front size deduced
2. Clean brine enters formation with little resistance
3. FeO_x and Ca-Inh precipitation were sources of problems
4. Inhibitor vs. flow results
5. New attempt :

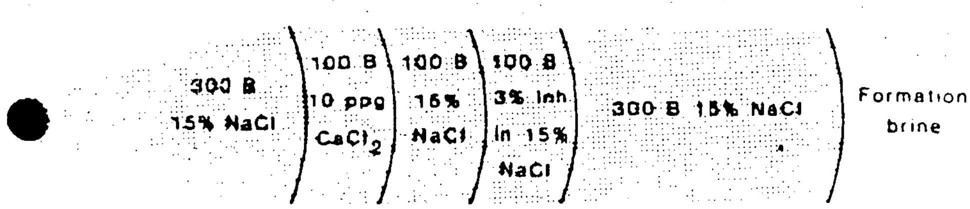


Figure 5-1. Inhibitor Squeeze Regime Gladys McCall No. 1.

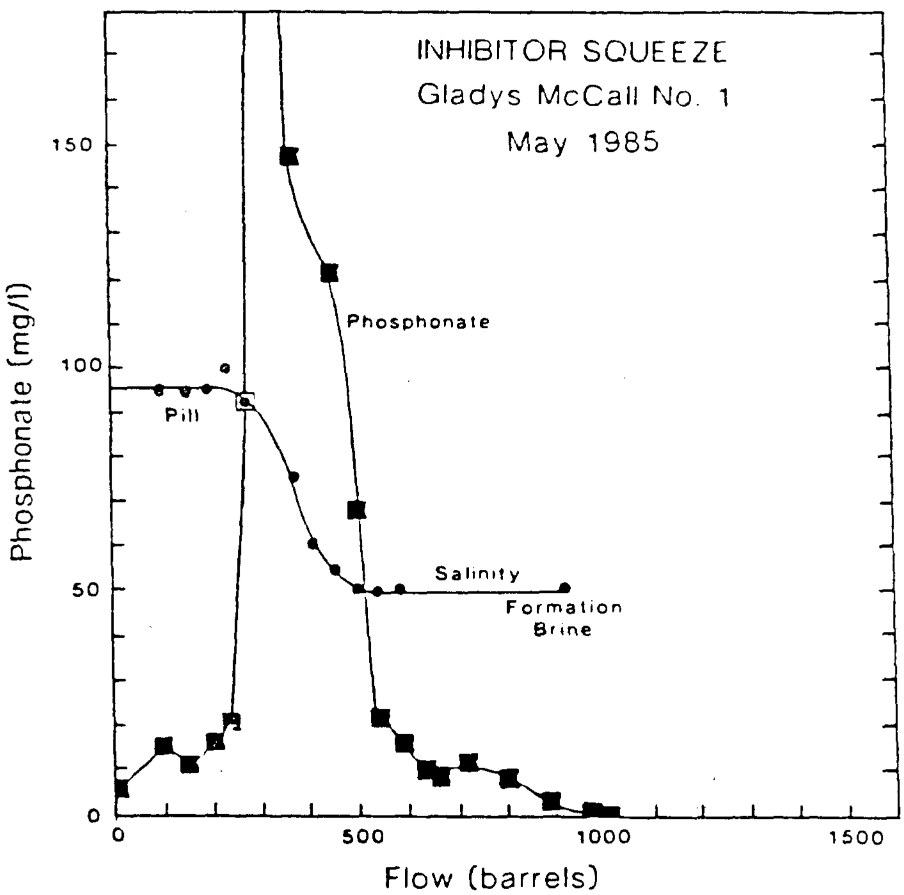


Figure 5-2. Results of attempted inhibitor squeeze treatment at the Technadril Fenix & Scisson/DOE Gladys McCall No. 1 well. Salinity curve shows mixing of injected pill (salinity - 150,000 ppm) with formation brine (salinity = 100,000 ppm). Phosphonate curve shows short period of effective inhibition.

This information was used to plan the pill which was applied in June, 1985. The estimated size of the mixing front or dispersivity allowed the use of smaller sodium chloride spacers and a smaller calcium chloride overflush. Stringent specifications were placed on all the fluids to be used for the pill to preclude the possibility of Ca-inhibitor or iron oxide precipitation. Fluid preparation was monitored to ensure that specifications were met.

Details of the inhibitor squeeze procedures are discussed in the attached daily testing report from Technadril-Fenix & Scisson. See Appendix B. Most of the fluids were successfully pumped into the formation. The well was shut in for 24 hours to enhance the adsorption and/or precipitation of inhibitor in the formation. Following the initial 48 hour flowback period at a rate of 2400 barrels per day (b/d), the production rate was increased to 25,000 b/d. This rate was maintained for 25 days, then increased to 31,000 b/d on July 24. At present, based upon observations of surface coupons and on the absence of frictional pressure loss in the production tubing, there is no evidence of scaling in the well. Trace phosphonate analyses of the most recent brine samples are being done now. Samples were taken upon flowback following a rigorous schedule, so that detailed mixing information could be obtained.

Ninety-five samples taken during the initial pill flowback period (200 to 500,000 barrels out) were sent for trace element analysis. Data show that over 60% of the inhibitor was returned immediately, indicating a limited life span for this treatment. See Figure 5-3. The remaining data was modelled using a numerical simulation to determine fluid mixing in the formation. This work was done by Tom Clemo of Idaho National Engineering Laboratory (INEL),

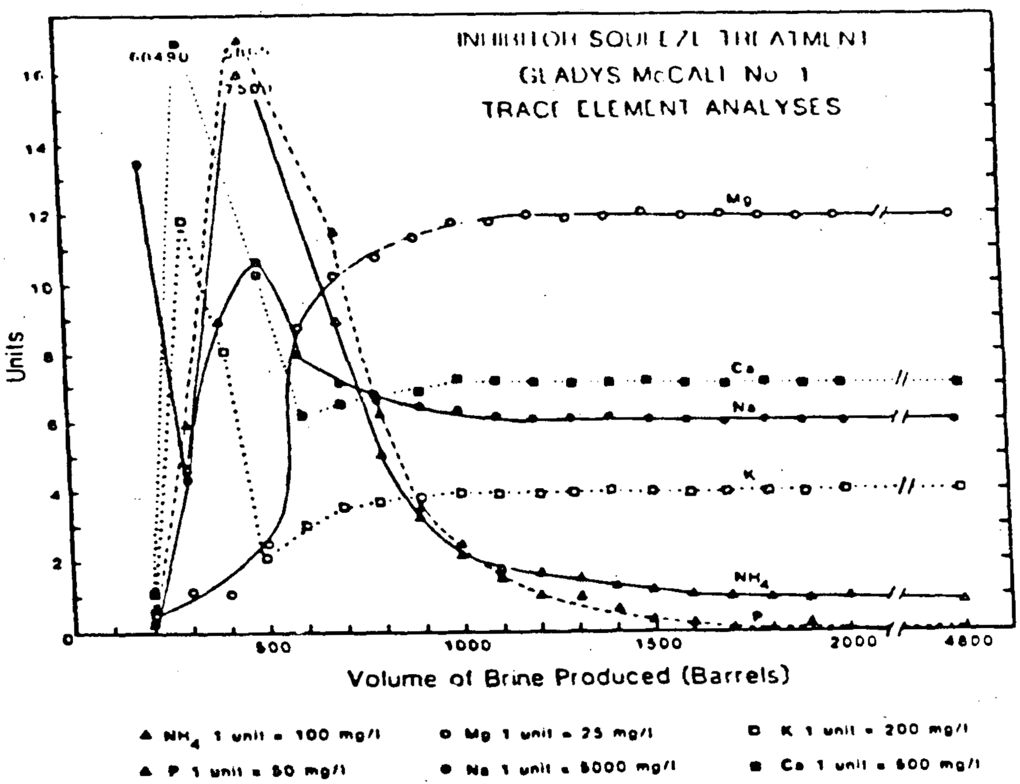


Figure 5-3. Trace element concentrations, inhibitor squeeze treatment, Gladys McCall No. 1 well. NH_4 and P track inhibitor: 60% returned by 1,000 barrels out. Mg tracks percent of formation brine; dominates by 1,000 barresl out. Ca peak traces CaCla overlfush. K peak may indicate ion exchange for Ca on clays in formation. Na traces NaCl spacers relative to formation brine.

Idaho Falls, ID (See Appendix C). He fitted both a Gaussian and an integrated Lorentzian function to the Mg data from the samples. It appeared that the Mg data were the most reasonable tracer data in the samples. The results were not as unique with respect to the calculated dispersivity as would be necessary to do detailed design of the pill regime. Hopefully, a better tracer can be added to the next pill to be used in the subsequent modelling efforts. Unfortunately, it is inherently difficult to get unique dispersion information from push-pull tests such as these. A range of dispersivities from 0.1 to 3.0 ft were tested for their effect on the mixing profile along with differing lead spacers and overflush volumes. It is believed that the dispersivity for the formation is probably about 2 to 3 ft. If this is correct, it should be possible to do an inhibitor squeeze without the use of any calcium chloride overflush to set the inhibitor up as an insoluble calcium salt. This would facilitate the use of bayou water as the background flush needed for a squeeze, which would also cut pump time costs. Further conversations are in progress to finalize the details of the next squeeze. See Appendix C for detailed information on the calculations. Samples of solid material were found in the filters at the well during August. These were analyzed and found to be 29.7%w Ca (equivalent to 74.3%w $CaCO_3$), 2.64%w iron, and 0.33%w phosphonate (as ATMP). It was determined that this material had formed earlier, and was just recently dislodged and caught in the filters.

As of 31 December 1985 the Gladys McCall well was still flowing at 25,000-30,000 BPD of brine. Some scale buildup had been noted in the filter pots just before the disposal well, but about 0.13 ppm inhibitor injected into the brine immediately after the tree prevented further scale. It is clear that scale formation is not taking place in the production tubing. A new squeeze is planned for the end of January, 1986.

IV. ADDITIONAL ACTIVITIES DURING THE PAST YEAR

A. BRINE CHEMISTRY KIT FROM LAMOTTE.

AN EASY TO USE KIT TO MEASURE: 1) CALCIUM OR HARDNESS; 2) ALKALINITY; AND 3) TOTAL DISSOLVED SOLIDS (TDS). EACH MEASUREMENT COSTS ABOUT $2.00 AFTER PURCHASE OF KIT FOR $280.00.

B. ANALYTICAL METHOD FOR LOW PHOSPHONATE INHIBITOR CONCENTRATIONS IN FIELD BRINES.

BY PUBLISHED METHODS THE LOWER LIMIT OF PHOSPHONATE CONCENTRATIONS IN BRINES WITH NUMEROUS TRACE ELEMENTS IS ABOUT 0.2 TO 0.5 MG/L. INHIBITORS ARE OFTEN EFFECTIVE DOWN TO 0.1 MG/L. AN EXTRACTION AND REDUCTION METHOD HAS BEEN DEVELOPED TO MEASURE PHOSPHONATES IN BRINE DOWN TO 0.01 TO 0.02 MG/L.

C. EFFECT OF MG^{2+}, SR^{2+}, BA^{2+}AND SO_4^{2-} ON INHIBITION OF $CACO_3$ PRECIPITATION.

THESE IONS ARE COMMONLY PRESENT IN FIELD BRINES. IT WAS KNOWN THAT THEY COULD AFFECT THE RATE AND COURSE OF $CACO_3$ PRECIPITATION. ALL EXPERIMENTS WERE DONE AT 120^{0}C (248^{0}F), 2M SALT, 500 PSI, AND 7.5 ML/MIN FLOW RATE. THE INHIBITORS USED WERE DEQUEST 2000 AND DEQUEST 2010. STONTUIM, SR^{2+}, WAS FOUND TO HAVE NO EFFECT UPON CALCITE NUCLEATION. ONCE THE INHIBITION LEVELS OF MG^{2+}, BA^{2+} AND SO_4^{2-} WERE ESTABLISHED, THE INHIBITION EFFECT UPON CALCITE NUCLEATION WAS ESSENTIALLY ADDITIVE.

D. INHIBITION OF CALCITE NUCLEATION WAS STUDIED OVER A WIDE RANGE OF $T_{CA^{2+}}/T_{CO_3^{2-}}$ RATIOS, PH'S AND FLOW RATES IN ORDER TO CHECK THEORETICAL PREDICTIONS.

AGREEMENT WAS NEARLY QUANTITATIVE OVER ALL VARIABLES, GIVING GREATER CONFIDENCE TO THE NOTION THAT INHIBITORS ARE "PRETTY MUCH THE SAME" AND SHOULD BE PURCHASED ON A GENERIC BASIS CONSIDERING SUCH THINGS AS COST, SERVICE, STABILITY AND OVERALL SYSTEM COMPATABILITY.

E. INHIBITION OF $CASO_4$ NH_2O NUCLEATION CALCIUM SULFATE IS THE SECOND MOST COMMON SCALE COMPONENT IN GAS AND OIL PRODUCTION. TECHNIQUES HAVE BEEN DEVELOPED TO STUDY THE INHIBITION OF $CASO_4$ NH_2O NUCLEATION IN THE LABORATORY AT HIGH T, P, AND TDS AND AT LINEAR FLOW RATES TYPICALLY ENCOUNTERED. INITIAL RESULTS HAVE <u>NOT</u> CONFORMED WITH ELEMENTRY NUCLEATION INHIBITION THEORY, AND AS TIME PERMITS ADDITIONAL TESTING AND THEORETICAL WORK ARE PLANNED.

F. POROSITY LOSS VS. RADIAL DISTANCE INFORMATION. -SUGGESTED BY LONNIE ANDERSON OF EATON OPERATING COMPANY - AN ANALYTICAL SOLUTION OF THE RATE OF POROSITY LOSS NEAR WELL BORE AS A FUNCTION OF RADIAL DISTANCE, FLOW RATE, AND HYDRAULIC CODUCTIVITY HAS BEEN COMPLETED AND RESULTS APPEAR TO BE REASONABLE.

MOST PLUGGING OCCURS WITHIN 1 TO 3 FEET OF THE WELL BORE. THIS IMPLIES THAT IF INHIBITORS COULD BE SQUEEZED SO AS TO SET-UP AT GREATER THAN THESE DISTANCES FROM THE WELL, POROSITY LOSS MIGHT BE PREVENTED WHILE INHIBITING WELL SCALING.

G. PRECIPITATION KINETICS OF FERROUS CARBONATE, SIDERITE ($FECO_3$). A MIXED $FECO_3/CACO_3$ MATERIAL MAY BE A BETTER MODEL OF WELL BORE SCALE THAN CALCITE. ALSO, $FECO_3$ MIGHT BE EFFECTIVE AS A CORROSION INHIBITION AGENT IN HIGH CO_2 WELLS (SUGGESTED BY A. K. DUNLAP OF SHELL DEVELOPEMENT). IT APPEARS THAT THE PRECIPITATION AND PRECIPITATION KINETICS OF $FECO_3$ MAY BE QUITE DIFFERENT FROM $CACO_3$; CONTRARY TO EXPECTATION.

V. IMMEDIATE DIRECTIONS

A. MONITORING GLADYS MCCALL WELL AND HITCHCOCK WELLS AND PORT ARTHUR WELLS.

B. FATE OF INHIBITORS IN FORMATIONS AND FORMATION MATERIALS.

C. CORROSION/SCALE RELATIONSHIP.

D. COMPLETE THEORY OF INHIBITION.

D. APPENDIX 4

GLADYS McCALL WELL MEASUREMENTS
INCLUDING DISCUSSION AND CONCLUSIONS

P. RANDOLPH/T. OSIF - IGT

GLADYS McCALL WELL

P.L. Randolph

Institute of Gas Technology

This presentation consists of seven (7) plots that portray the production history of sand #8. Significant points to be made are:

1. Brine rates previously reported were at separator pressure and temperature. The values shown are lower due to correction to stock tank conditions of 60 Deg F and atmospheric pressure.

2. Since the middle of the 2nd quarter of 1984, the high pressure separator has been operated at 1000 psi to drive the gas sales line without compression. Gas from the low pressure separator is compressed to sales pressure. With the exception of times when the disposal well mandated higher presssure, the 2nd stage separator pressure has been the lowest value that would keep CO_2 content of gas sold below the buyers specification of 10%.

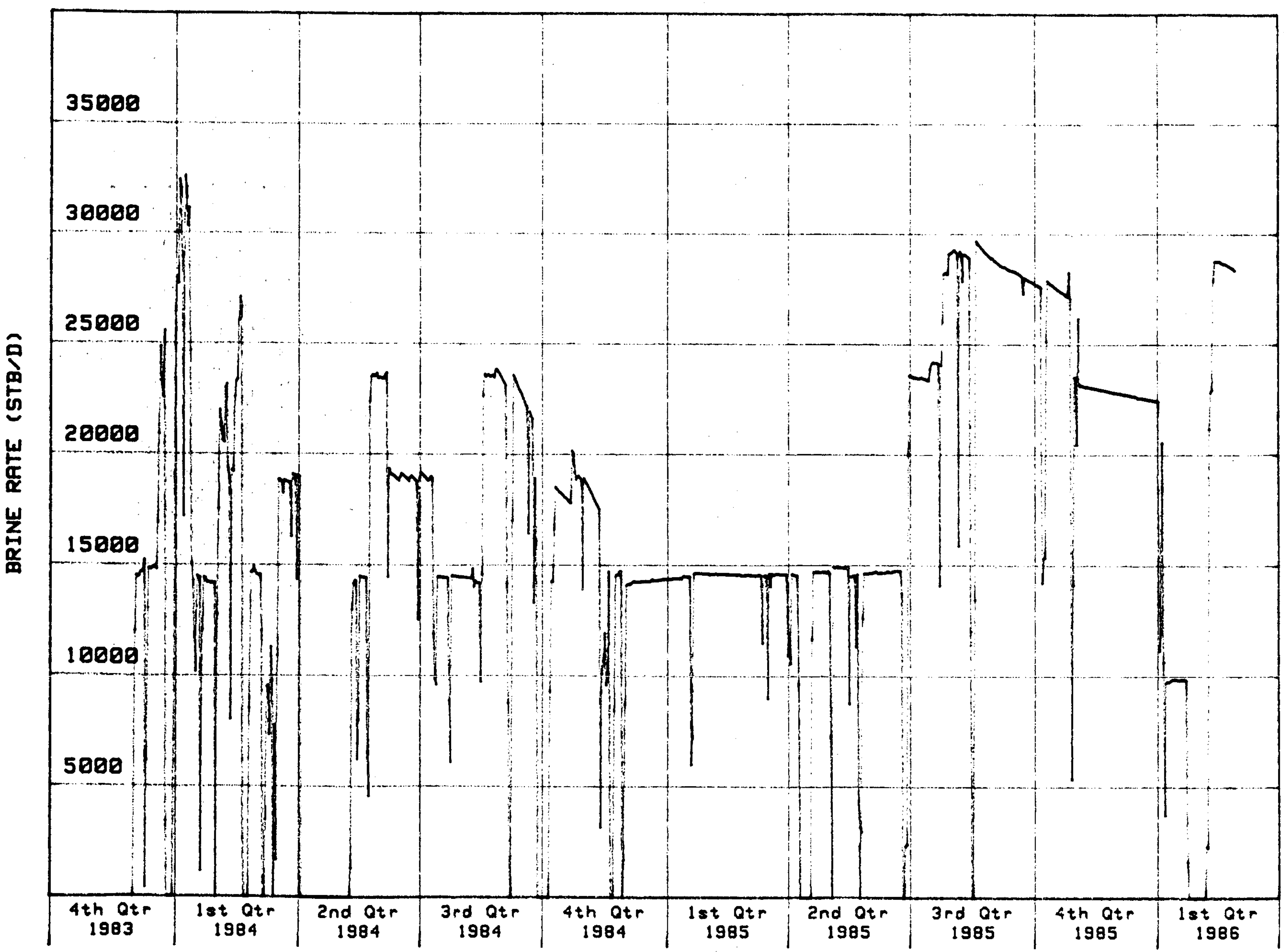
3. Total produced gas/brine ratio has been estimated by adding IGT's calculation of gas remaining in brine to the disposal well to the gas/brine ratios for the two separators. The plotted result shows an average of about 29 SCF/STB for the entire production history. The minor variations do not correlete with other production parameters in a consistent manner.

4. Scaling in the production tubing was a major factor prior to the middle of the 4th quarter of 1984. This is apparent from the falloffs in wellhead pressure and brine rate that were much greater than since the successful use of inhibitor squeezes.

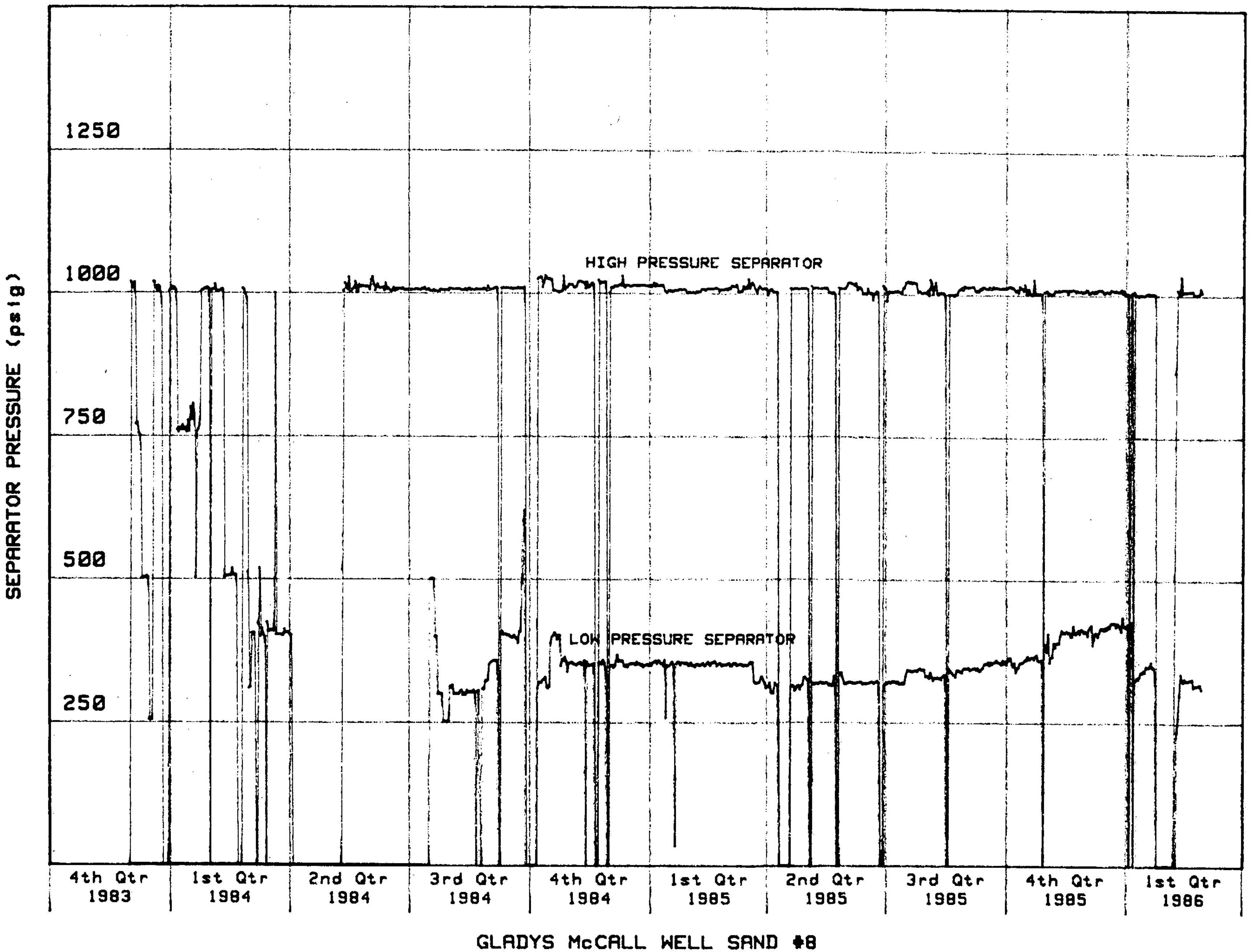
5. Ignoring the erroneous values due to scale in the tubing, IGT's calculation of bottomhole flowing pressure indicates that the current value of about 9200 psia is the lowest that has been achieved to date for the well. This is very near to the bubble point determined in laboratory PVT work by Weatherly Laboratories(The BHP calculation was verified to be within 20 psi by comparison with the value measured at a 10,000 bpd flow rate in January, 1986).

6. The NGL content of gas from the first stage separator has been consistently about 0.94 Gal/MCF for most of the life of the test. This further suggests that a significant portion of the reservoir has not yet been drawn down to below the bubble point.

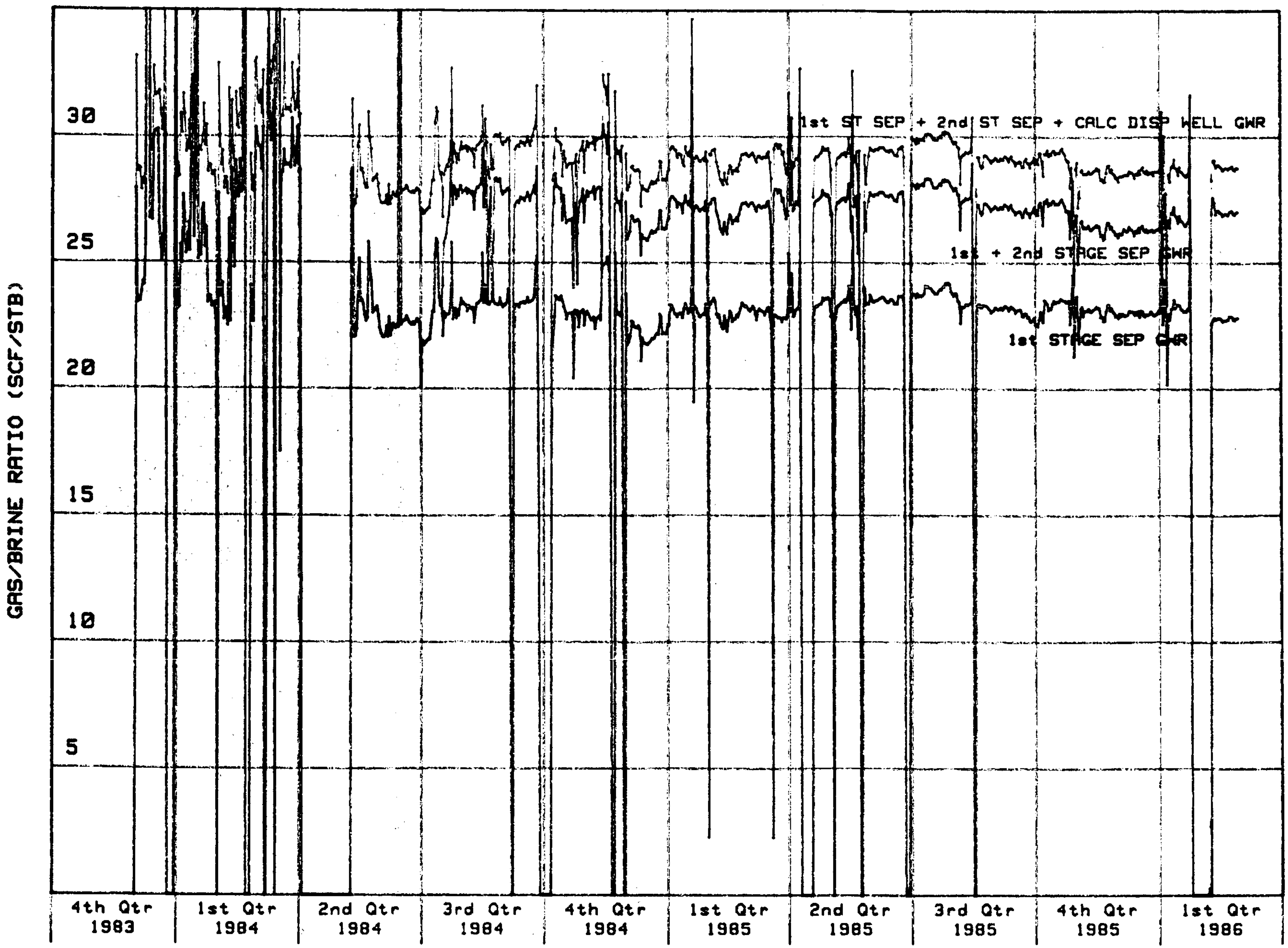
7. Evidence that the reservoir was <u>not</u> saturated with gas at the original pressure is becoming increasingly strong.



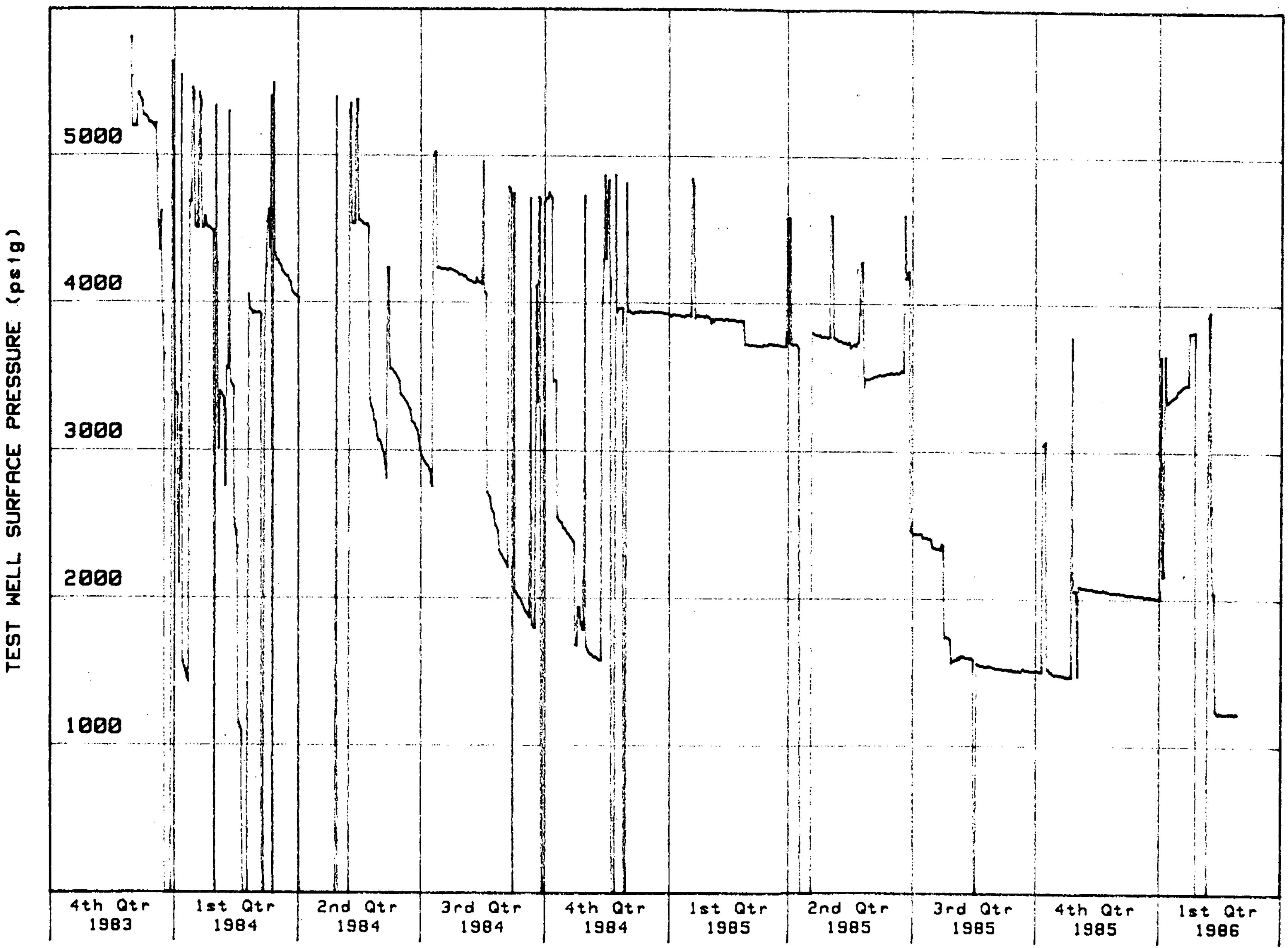
GLADYS McCALL WELL SAND #8



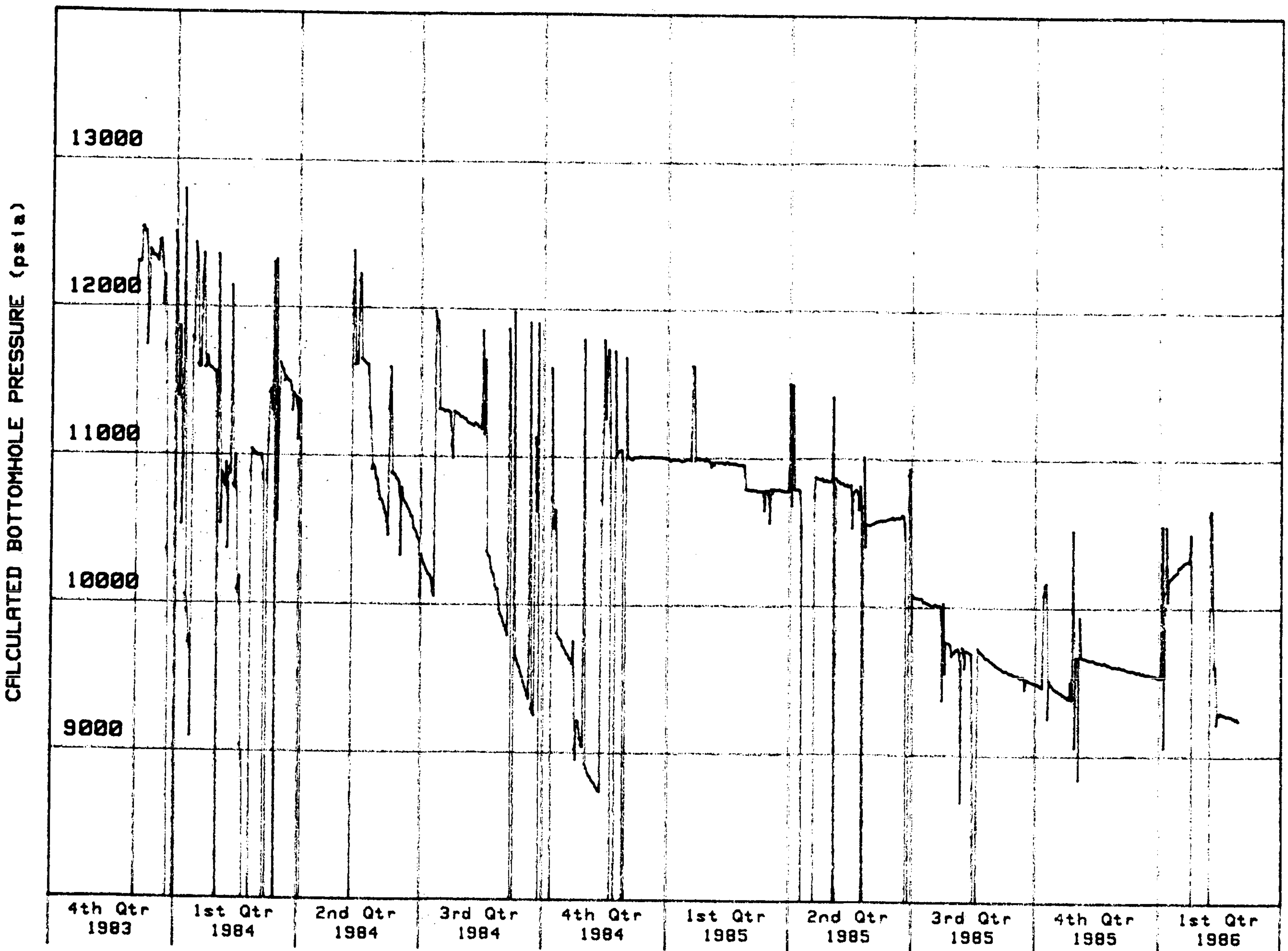
SEPARATOR PRESSURE (psig)
1250
1000
750
500
250
HIGH PRESSURE SEPARATOR
LOW PRESSURE SEPARATOR
4th Qtr 1983
1st Qtr 1984
2nd Qtr 1984
3rd Qtr 1984
4th Qtr 1984
1st Qtr 1985
2nd Qtr 1985
3rd Qtr 1985
4th Qtr 1985
1st Qtr 1986
GLADYS McCALL WELL SAND #8



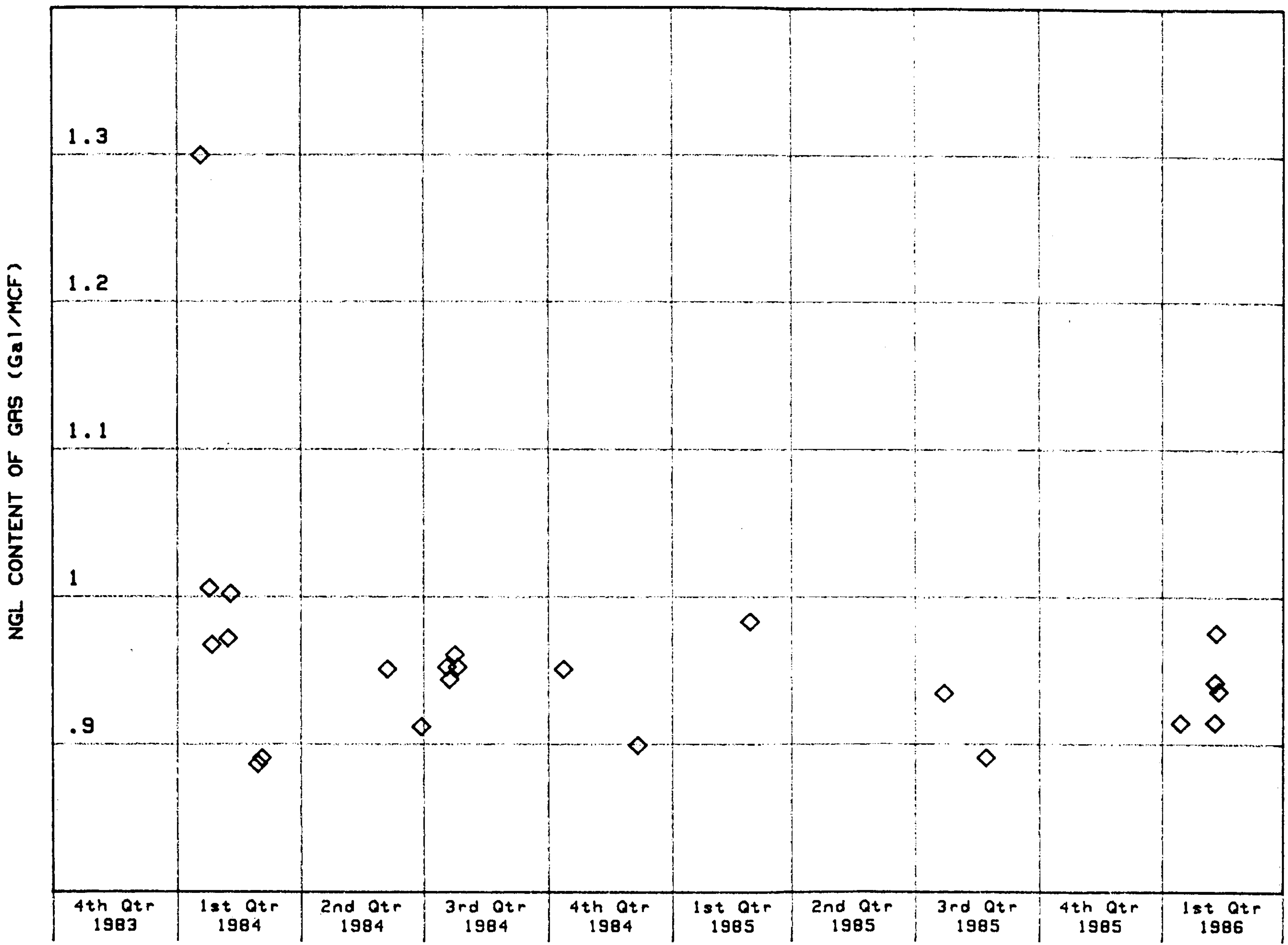
GLADYS McCALL WELL SAND #8



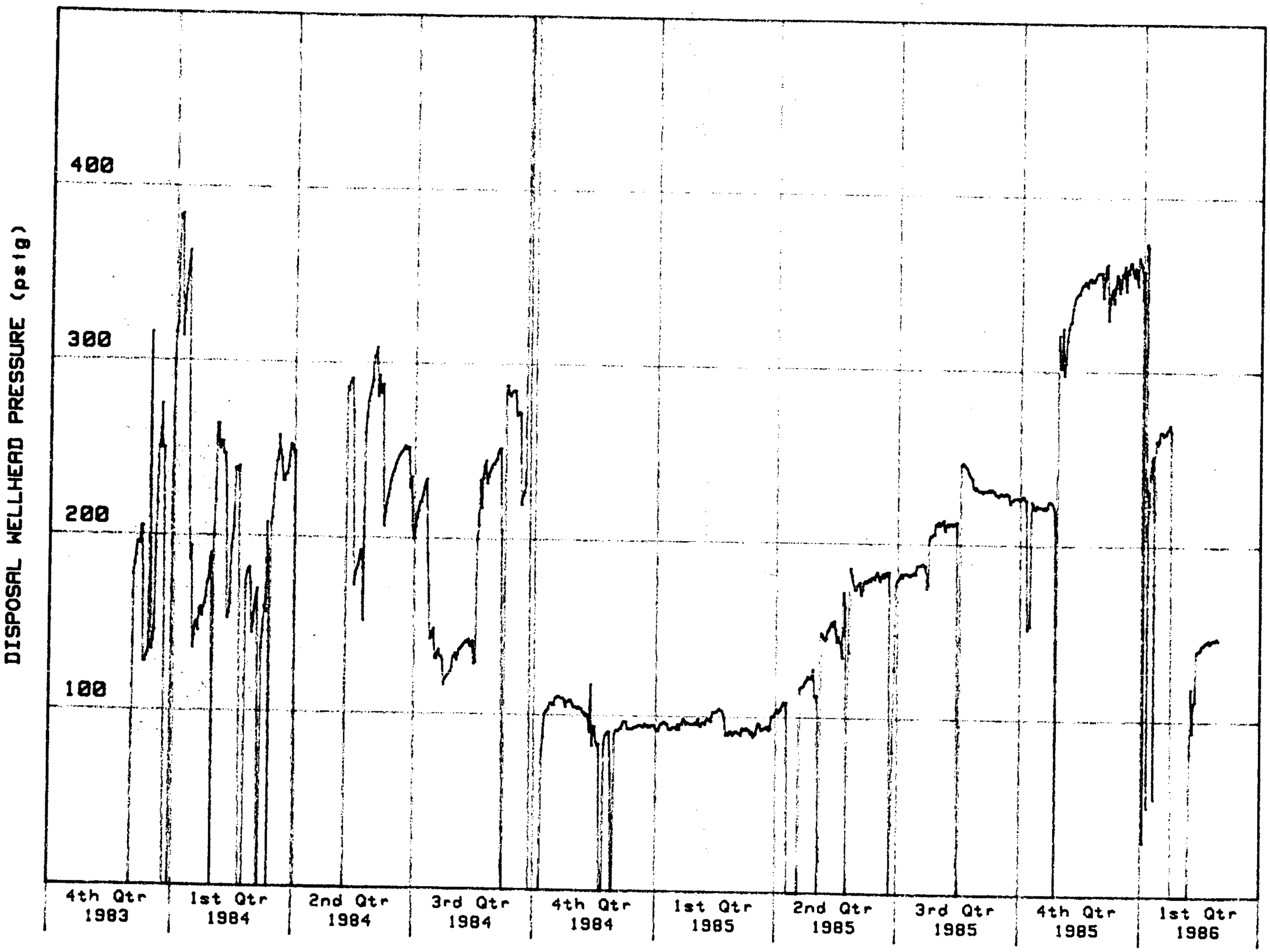
GLADYS McCALL WELL SAND #8



GLADYS McCALL WELL SAND #8



GLADYS McCALL WELL SAND #8



GLADYS McCALL WELL SAND #8

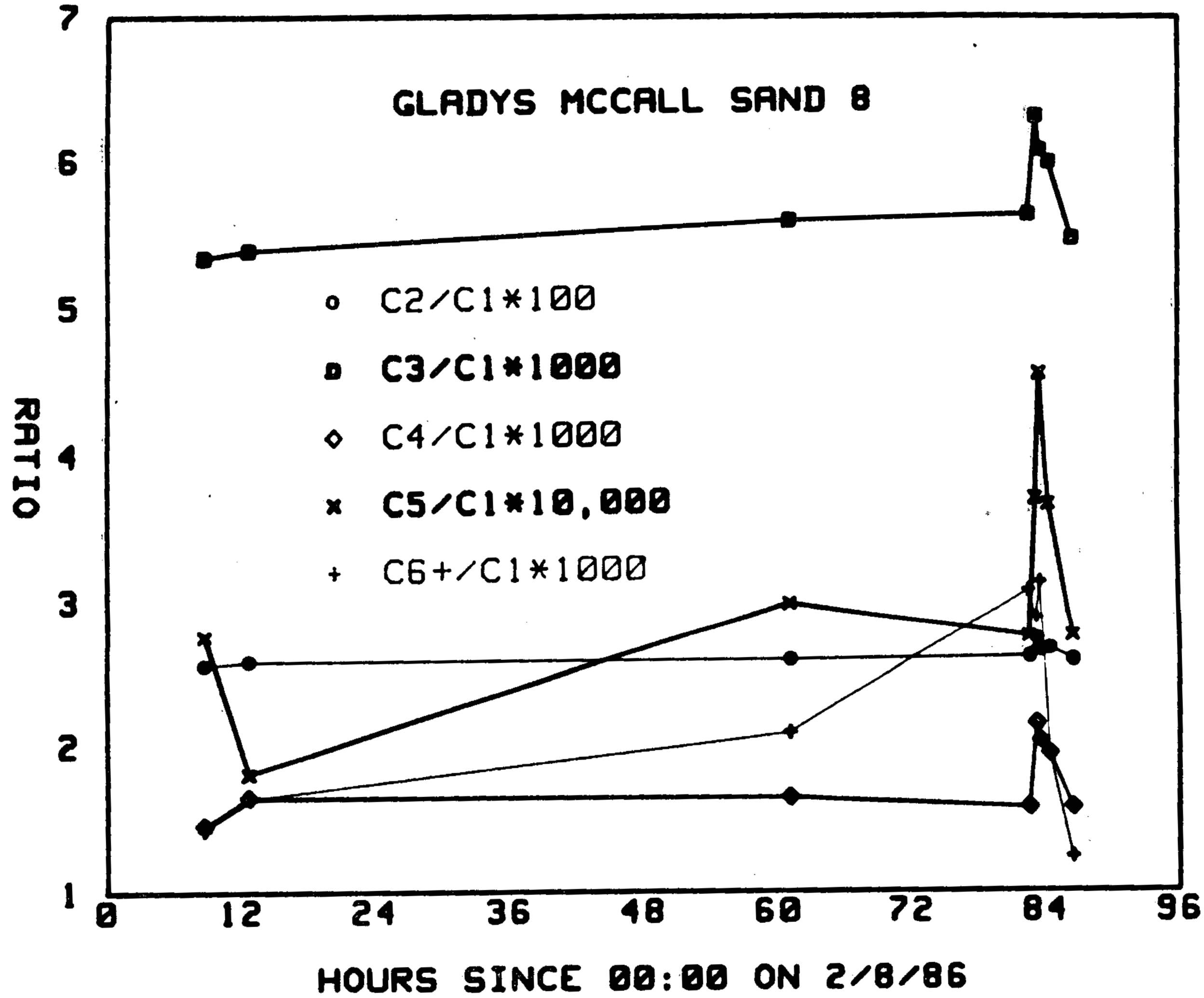


Figure 1. Total Produced Gas Hydrocarbon Ratios Versus Time

The peak in all the hydrocarbon ratios (i.e., the change in total gas composition), at about hour 8 4 (which is 12 noon 2/11/86) shows that a small amount of free gas was produced for an hour or two after the brine rate was increased from about 23,000 to about 28,500 BPD. The decrease in BHP caused by the rate increase allowed the free gas near the wellbore to expand above critical gas saturation and flow. As the free gas was produced, the gas saturation decreased and free gas production ceased. This shows that the near wellbore reservoir was drawn down below the bubble point sometime prior to 2/11/86. Use of a computer program developed by IGT to calculate inside casing BHP from surface measurements shows that the lowest pressure reached before the above mentioned rate increase was 9525 psia reached on 1/2/86. This is the first evidence that the near wellbore reservoir has been drawn down below the bubble point. PVT work predicted a bubble point of 9200 psia.

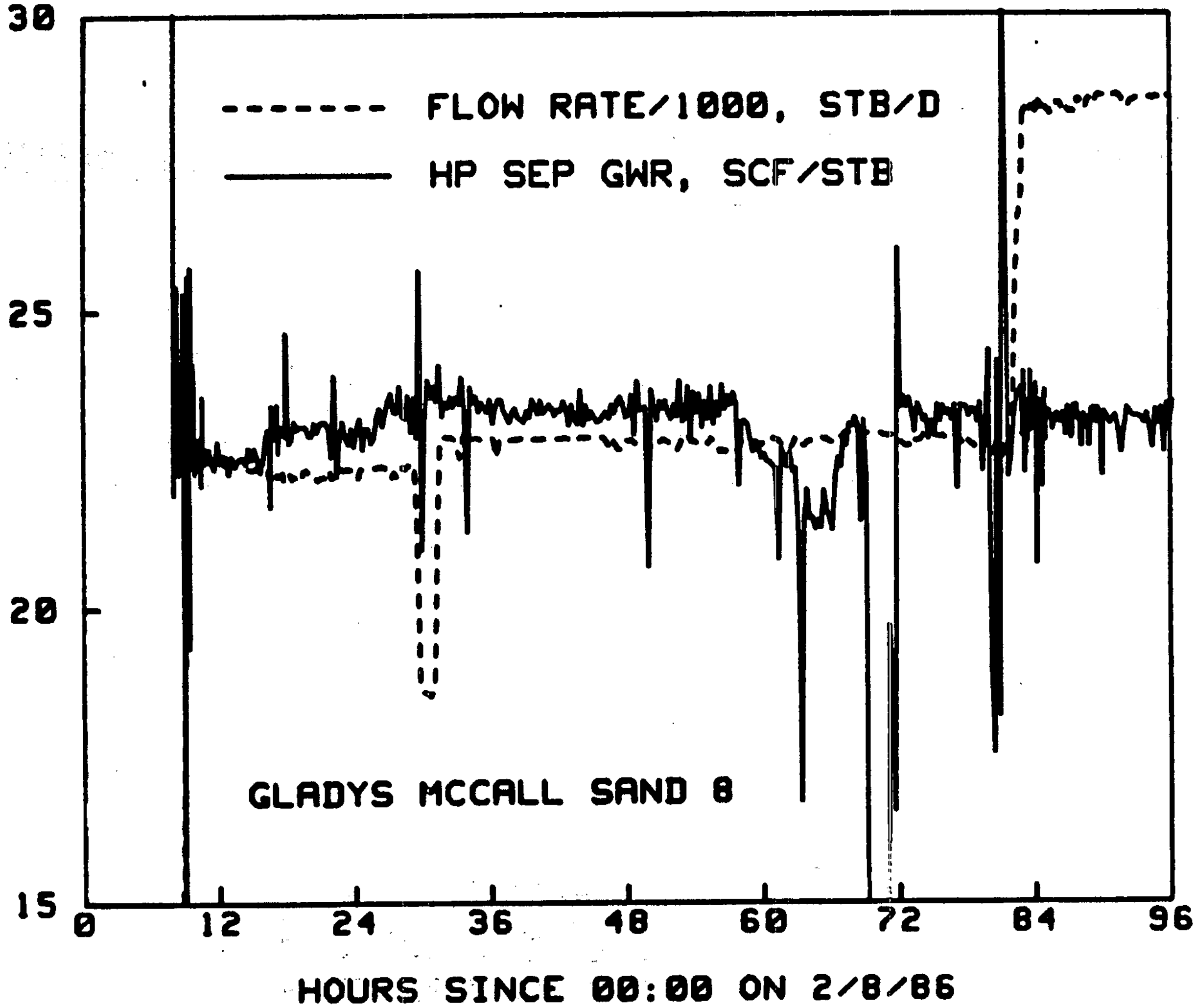


Figure 2. Flow Rate and High Pressure Separator GWR

This shows a computer generated plot of computer collected and calculated data made possible by the computer system installed by IGT (Note that the flow rate recorded in SEPB/D was converted to STB/D by the computer). Around hour 84, the computer system was recording averaged data every two minutes. Note that the free gas production was so small that it can't be seen looking at the GWR in Figure 2; however, the change in composition technique shown in Figure 1 is so sensitive that the free gas production in quite obvious.

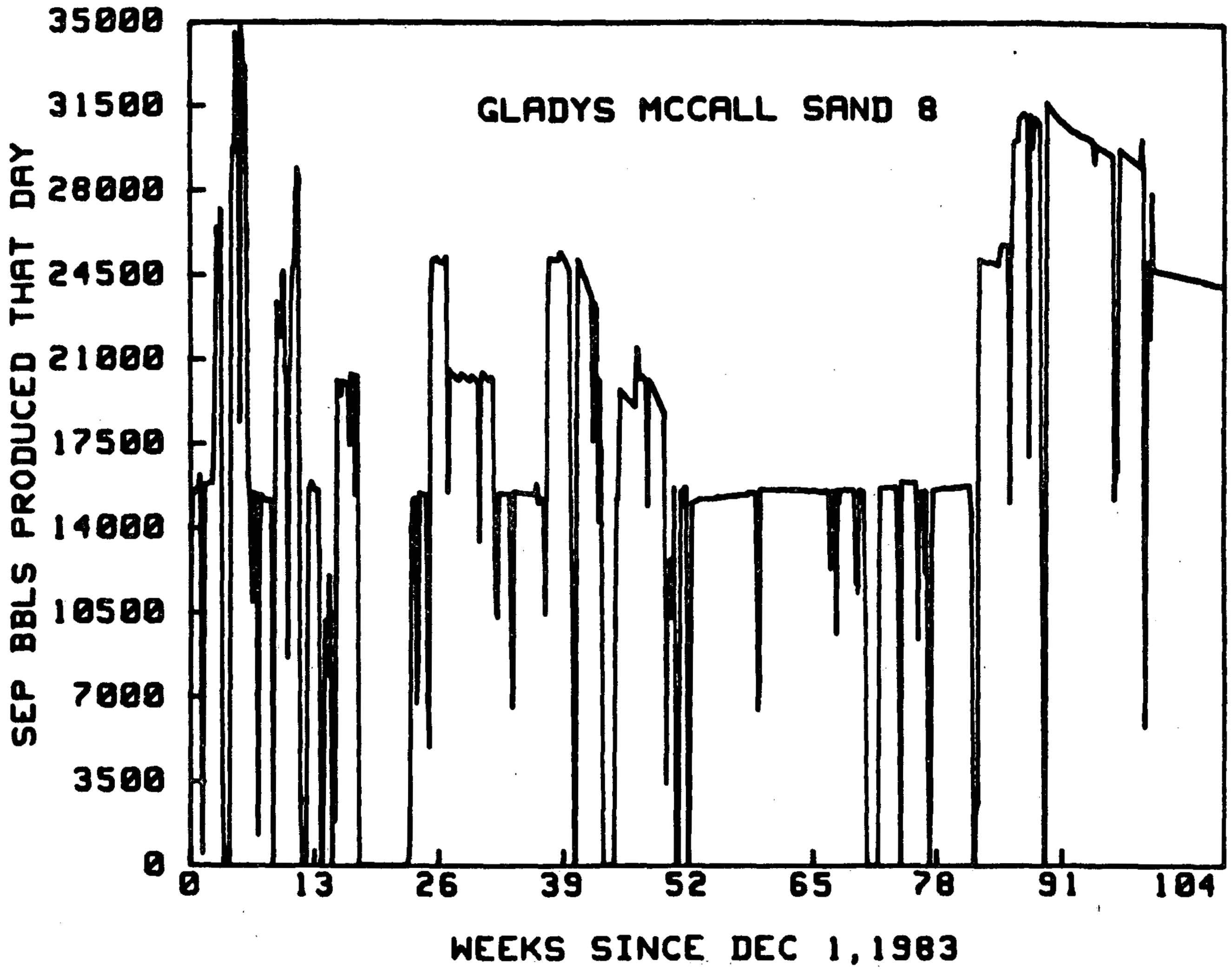


Figure 3. Plot of Barrels of Separator Brine Produced in a Day Versus Time.

These values were hand recorded. The downward spikes are not necessarily due to a decrease in flow rate, but rather to a shut-in for part of a day.

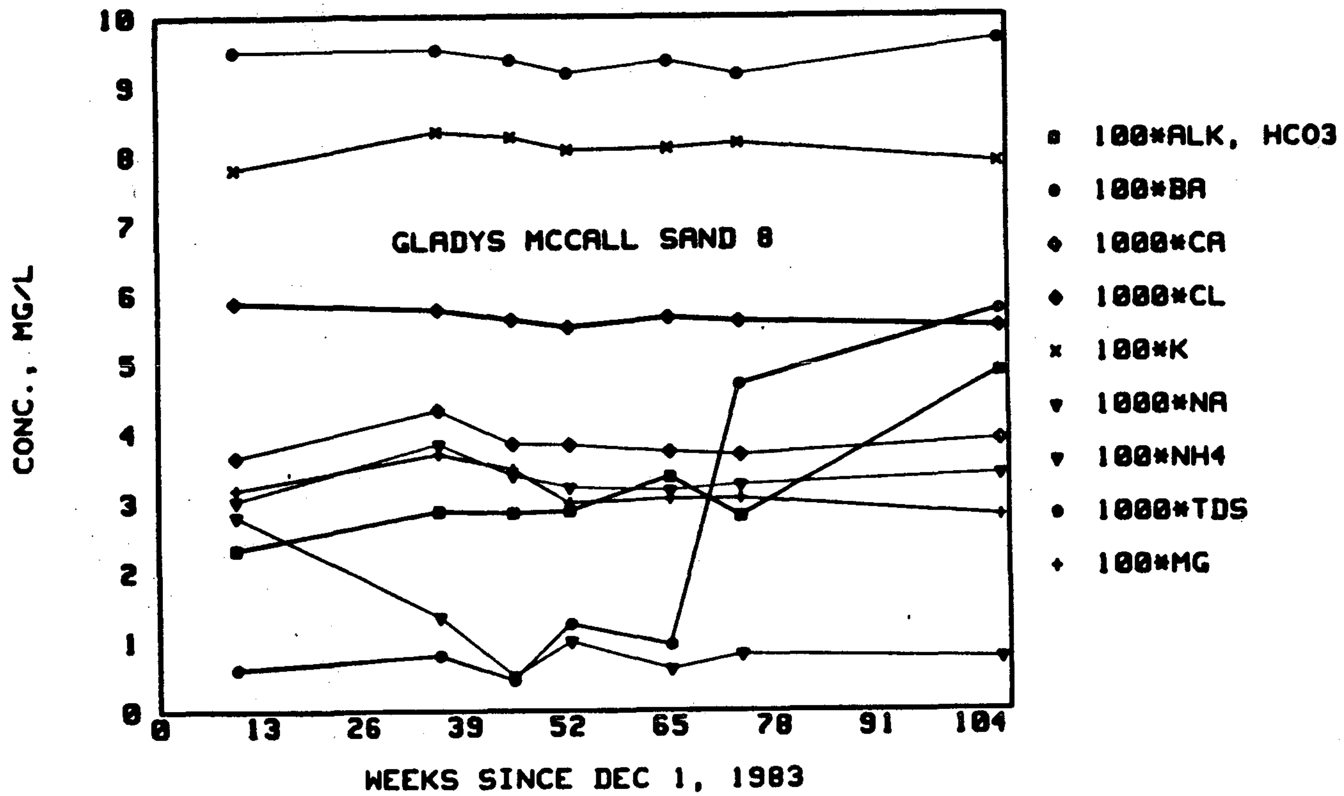


Figure 4. Brine Analyses

The analyses done about week 107 were done by IGT. The rest where done by SCAN. The alkalinity measured by IGT was measured on site soon after the brine sample was taken. It is greater than the alkalinities measured by SCAN. SCAN and IGT use the same measurement technique and the value measured by IGT is in excellent agreement with the values obtained using the operator used colorimetric technique developed by Rice University. The change in alkalinity is probably due to changes in scaling and/or scaling treatment. The last two Ba measurements are greater than the others. The fact that both labs measured the higher values suggests that they are correct. It is conceivable the IGT Ba is due to particles of barium sulfate so small that they get through 0.47μ) filters, but this is highly unlikely. The initial ammonium concentration was greater than the others. The reason is unknown at this time.

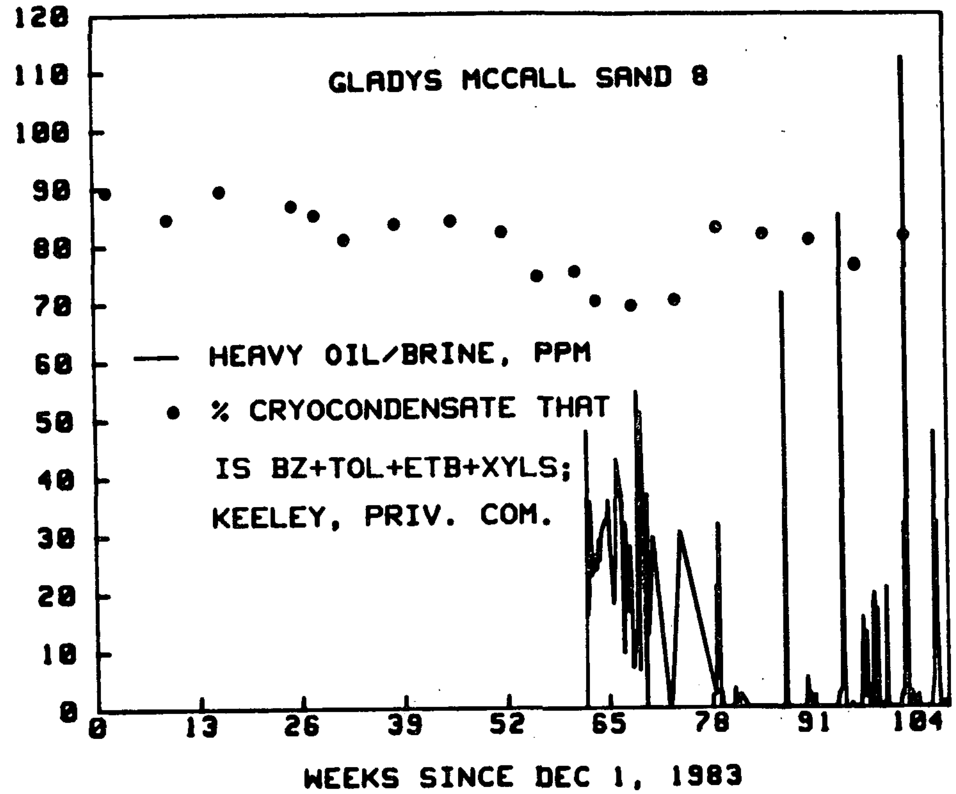


Figure 5. Cryocondensate and Heavy Oil Production

The heavy oil has also been called paraffinic and aliphatic oil. It was first found as a separate phase in the high pressure separator on 1/19/85. The cryocondensate is aromatic hydrocarbons condensed from the high pressure separator gas at dry ice temperature. At least part of the spikes in the heavy oil plot are due to the measurement technique. The decrease in the % cryocondensate occurring between weeks 56 to 74 (during continuous heavy oil production) is due to an increase in intermediate aliphatic hydrocarbons (C9-C13) that were produced with the aliphatic oil. The decrease between weeks 51.4 to 56 indicate that the heavy oil production began between those times. The decrease at week 96 suggests that heavy oil was being produced at the time, but it was collected and measured later. The increase at week 102 occurring on a spike of heavy oil production, suggests that the heavy oil was actually produced earlier than it was collected and measured. IGT has requested that stinger tubes be placed in the separators and values be placed on the sight glasses so that they can be blown out. These changes were made and should help improve heavy oil measurements.

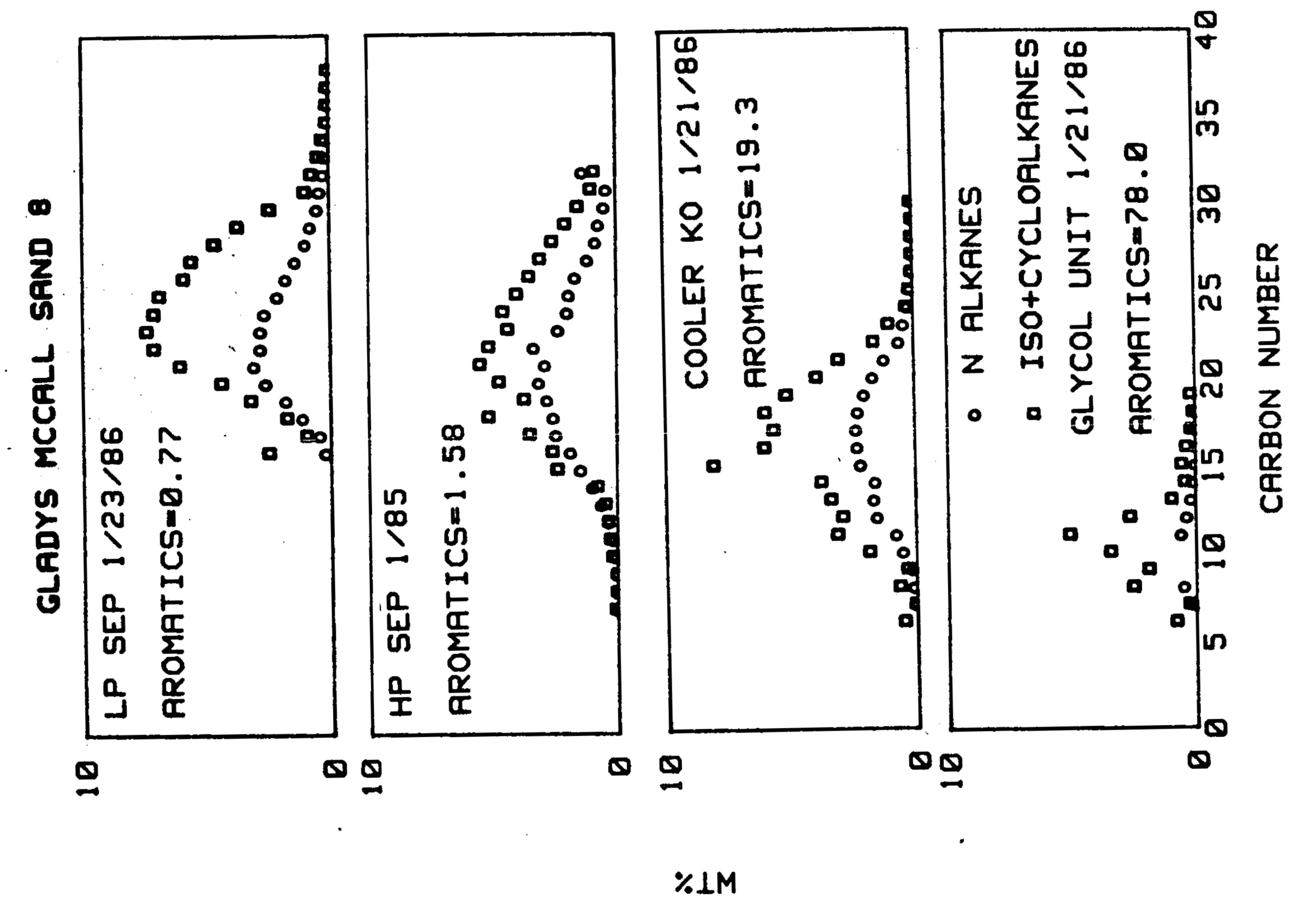


Figure 6. Capillary Column GL Analyses of Liquid Hydrocarbons

For each sample, each carbon number has more iso + cycloalkanes than n alkanes. The low pressure separator analysis shows that at least some of the heavy oil is being carried out of the high pressure separator by the brine. The analysis of the sample from the gas cooler knock out shows these hydrocarbons are leaving the high pressure separator as gas. As expected, this sample is lighter (more of the lower carbon numbers) than the separator samples and contains more aromatics. Until IGT asked that the liquids from the cooler knock out be collected in a tank, the liquids went unmeasured down the disposal well. Initial measurements after the tank was installed indicate that liquid hydrocarbon recovered from the knock out is about twice that recovered from the separator. The liquid hydrocarbons from the glycol unit is lighter than the rest and is very highly aromatic.

CONCLUSIONS ABOUT GLADYS MCCALL

* The aromatic hydrocarbons are dissolved in the brine in the reservoir.

* The amount of aromatic hydrocarbons dissolved in the brine changes with location in the reservoir.

* The heavy oil exists in the reservoir as a separate phase. It is not dissolved in the brine nor is its source a free gas phase in the reservoir. additional flow testing is needed to study the heavy oil production.

* The liquid hydrocarbons are distributed through the surface hardware. Initial measurements indicate that more liquid hydrocarbons are recovered from the gas cooler knockout than from the separator.

* The occasionally produced heavy oil is the source of the C9 to C13 aliphatic hydrocarbons collected in some of the cryocondensate samples.

* The changes in surface hardware initiated by IGT will result in better measurements of liquid hydrocarbon production.

* The total gas analyses done by IGT is a very sensitive technique that shows that the near wellbore reservoir was drawn down below the bubble point prior to 2/11/86. The lowest in casing BHP calculated by IGT was 9525 psia occurring on 1/2/86. The bubble point is higher than this. IGT has a GC on site and can thus analyze samples soon after collection. Also, using the same lab is a good practice when results are to be compared. Therefore, it is recommended that IGT do future gas analyses, particularly total gas analyses.

CONCLUSIONS ABOUT GLADYS MCCALL (CONT.)

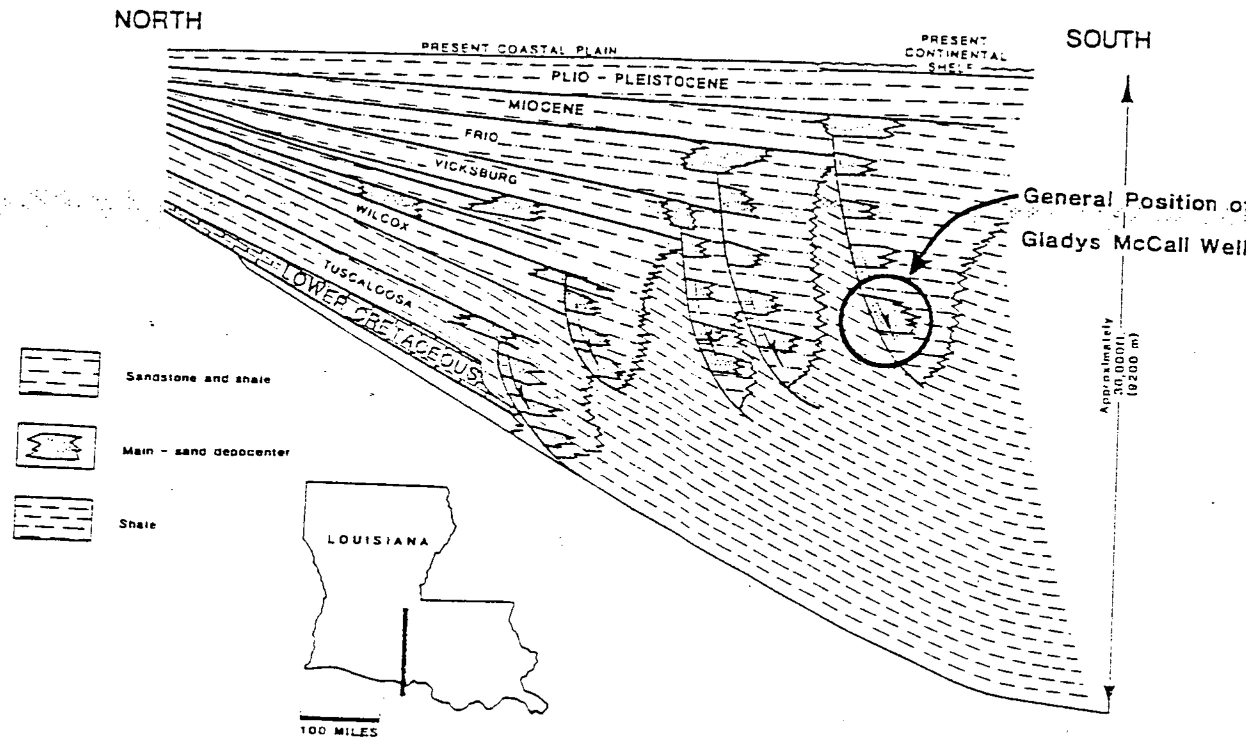
* A gas phase now exists in the near wellbore reservoir at critical gas saturations when the reservoir is flowing at about 30,000 BPD.

* The total gas composition should undergo very complex (though perhaps small) changes depending on past and future production procedures.

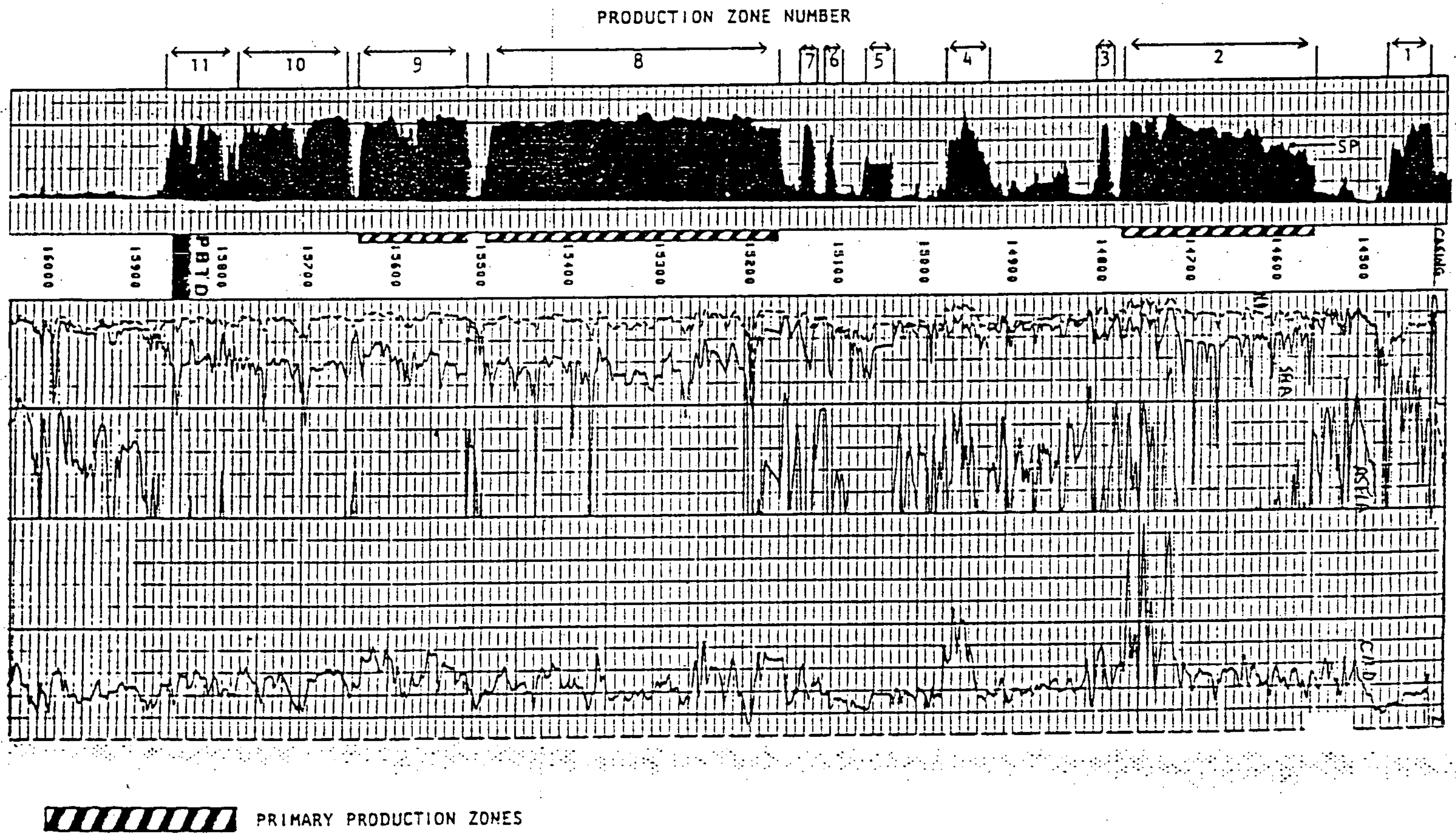
E. APPENDIX 5

GEOLOGY OF GLADYS McCALL RESERVOIR INCLUDING CROSS SECTIONS

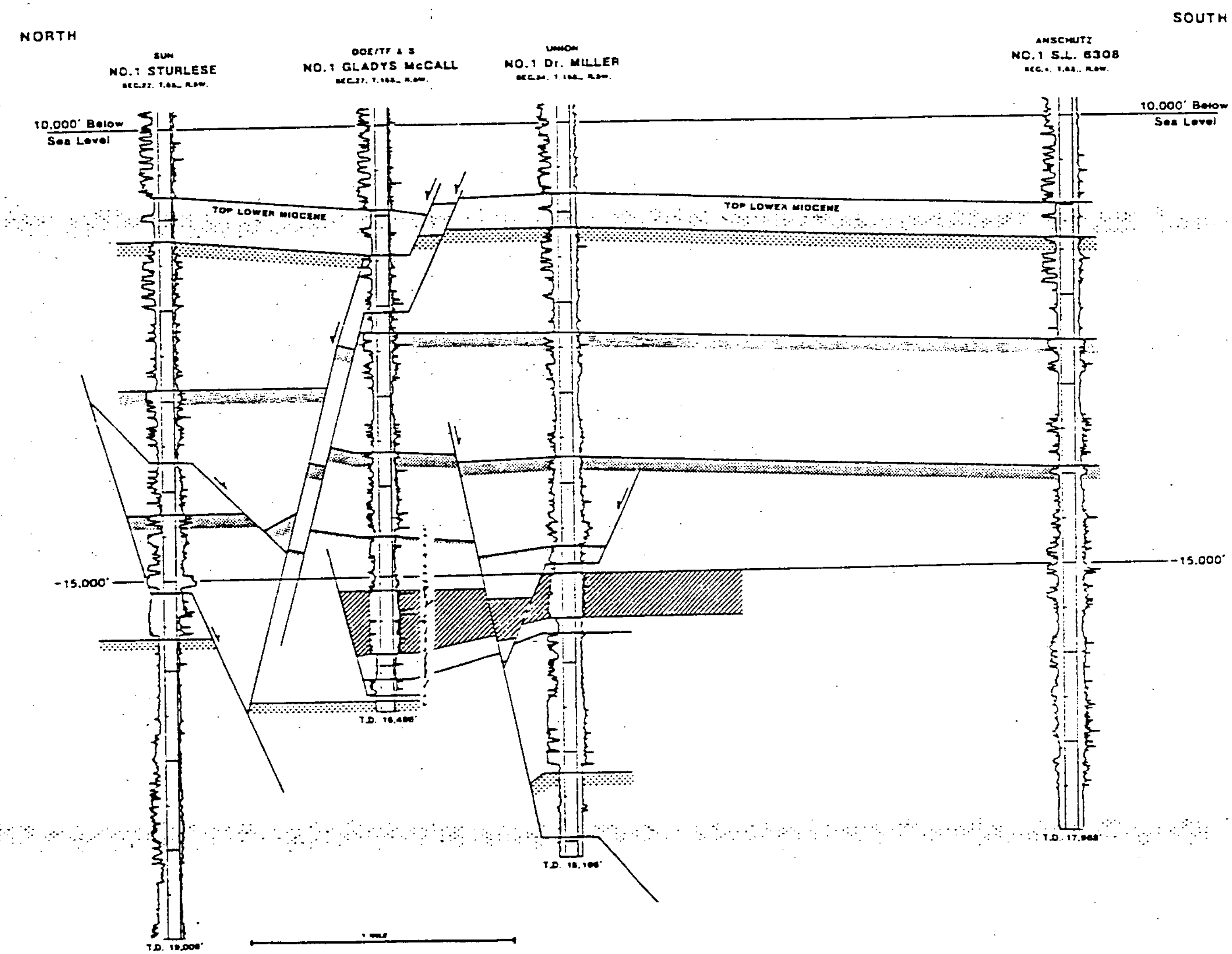
C. GROAT - LSU



-- Diagrammatic section across the geopressured zone of south Louisiana.



-- Logs of potential production zones in the T-F&S/DOE, Gladys McCall No. 1 well.



-- Detailed cross-section across the Rockefeller Refuge prospect area, showing correlation lines and dip-meter log. Faults as shown supported by an independent interpretation of seismic data by S. Brunhild.

F. APPENDIX 6

GLADYS McCALL RESERVOIR ANALYSIS INCLUDING DISCUSSIONS AND CONCLUSIONS

D. RINEY - S-CUBED

Gladys McCall Reservoir Analysis - March 1986*
T. D. Riney
S-CUBED
P.O. Box 1620
La Jolla, California 92038

1. Data Review and Analysis

Figure 1 presents a summary of the production history of the Gladys McCall No. 1 well from Sand Zone No. 8 from the time of the Reservoir Limits Test through the end of the 92-hour buildup test in January 1986. The depicted flow-rate history has been used as input in reservoir simulation studies to be discussed later herein. The well has been shutin for series of acid treatments for scale removal from the tubing on four occasions. After two early attempts to inhibit scaling by injection of phosphonate into the formation were aborted, successful "pill" injection has been accomplished twice.

Figure 2 shows the wellhead (surface tubing) pressures recorded at 07:00 hours from the time of the first acid treatment through the end of the 92-hour buildup test. Examination of these data indicate that injection of the scale inhibitor pill causes an increase in the skin factor. In November 1984 the well was shut for approximately 57 hours for the first attempt to inject an inhibitor pill (Figure 2a). Although the production rate both before and after shutin was ~ 15,000 B/D, the surface pressure after the well was reopened was actually less than just prior to shutin. Since the reservoir pressure certainly recovered significantly during the 57-hour shutin period, the inhibitor injected must have caused a decrease in the permeability of Sand Zone No. 8 near the wellbore. The pill injection attempt was aborted when the incremental injection pressure exceeded 600 psi. The pill flowback contained solid precipitates and formation plugging was suspected at the time.

The data from the second pill attempt more clearly demonstrates an associated increase in the skin factor (Figure 2b). In May 1985 the well was shut for approximately 120 hours while an attempt was made to inject an inhibitor pill. Although the production rate both before and after shutin was ~ 15,500 B/D, the surface pressure after the well was reopened was ~ 200 psi less than just prior to shutin. Over the next month the surface pressure actually increased even while drawdown continued. Apparently, the flow of the brine through the formation cleaned out much of the precipitates in the pores thereby recovering the near wellbore permeability to some extent.

Summary of presentation at DOE/Industry/GRI Geopressured Industry Forum, Houston, Texas, March 4-5, 1986.

During January through March 1985 ($5.8 < Q < 7.4$ sep bbls) the Gladys McCall well flowed at a nearly constant rate of

$$\bar{q} = 15{,}249 \text{ sep bbls/day.}$$

The plot of flowing surface pressure versus Q during this period (Figure 2a) yields a linear relation with slope 57.9 psi/10^6 sep bbls from which we estimate (assuming semi-steady state flow and that the scaling of the production tubing during this period is negligible so that the pressure loss in the wellbore is constant.) is

$$V_p C_T = 17{,}051 \text{ res bbls/psi}$$

If we take $C_T = 6.27 \times 10^{-6}$ psi^{-1}, then the corresponding reservoir pore volume is

$$V_p = 2.72 \times 10^9 \text{ res bbls.}$$

We note that this estimate is close to the value $V_p = 2.512 \times 10^9$ bbls employed in our simulation of the Gladys McCall reservoir.

The pressure buildup data measured during the 92-hour test of January 1986 (Figure 3) are in excellent agreement with the data from the 79-hour test of April 1985. Both yield a reservoir transmissivity (kH) equal to about half the value measured during the Reservoir Limits Test of November 1983. The reduction in transmissivity at the time of the 79-hour test is attributed to plugging of about half the perforations in Sand Zone No. 8 in conjunction with a shale stringer, identified at a depth of 15,365 to 15,369 feet. The combination is assumed to effectively reduce the sand thickness in direct communication with the wellbore from 332 feet at the time of the Reservoir Limits Test to the upper 207 feet at the time of the 79-hour test.

It appears that the plugging resulted from the November 1984 attempt to inject a scale inhibitor pill rather than the acid treatments. Table 1 compares the estimates for the 79-hour and 92-hour tests under the alternate assumptions (H = 332 or 207 feet) with the results of the Reservoir Limits Test. Under either assumption it appears that the skin factor, which had increased between the Reservoir Limits Test and 79-hour tests, had essentially returned to its initial value by the time of the 92-hour test.

2. Reservoir Model and Simulated History Match

Figure 4 shows the conceptual model that has evolved of the reservoir produced by Sand Zone No. 8. It is assumed that crossflow from sands overlying/underlying Sand Zone No. 8 is the cause of the observed pressure reservoir maintenance. The corresponding simulation model for the Gladys McCall reservoir includes a shale stringer at the middle of Sand Zone No. 8 (Figure 5). Since the overlying reservoir volume shown in Figure 5 can only supply recharge to Sand Zone No. 8 by inflow beyond the confining overlying shale layer, the model is numerically equivalent to the simulation model shown in Figure 6. This model with elastic rock properties and recharge from a "remote" reservoir volume provides matches both to the bottomhole pressure data and the production data up to the time of the 92-hour test.

We note that the value of the skin factor used in that the simulation update was changed from an initial value of $s = +4.3$ to a value of $+7.3$ at the time the lower half of the sand was plugged. There were no further changes made in the model; the production flow rate was merely updated as represented in Figure 1.

The agreement of the simulated history with the downhole measurements from the Reservoir Limits Test (Figure 7), the 79-hour buildup test (Figure 8) and the 92-hour buildup (Figure 9) is excellent.

The differences between measured values of the pressure at wellbottom and at the wellhead ($\Delta p_{WB} = p_{WB} - p_{WH}$) at very early times yield estimates for the hydrostatic pressure drop of $\Delta p_{hydr} \sim 6626$ psi (Reservoir Limits Test) and $\Delta p_{hydr} \sim 6600$ psi (79-hour test). Within the accuracy of the data, the available "instantaneous" shutin pressure measurements at the wellhead can be used to estimate the corresponding "instantaneous" wellbottom shutin pressures:

$$\left[p_{WB}\right]_{\Delta t = 0+} \sim \left[p_{WH}\right]_{\Delta t = 0+} + 6626 \text{ psi} .$$

Figure 10 compares these estimates with the wellbottom pressure history calculated using the simulation model updated through the time of the 92-hour buildup test. The simulated history is seen to also provide an excellent match to these data-based buildup pressures over the entire production history.

3. Model Predictions

Since the updated simulation model matches both the bottomhole pressure transient data and the surface buildup pressure data over the full production history of the Gladys McCall Well No. 1, it can be used with reasonable confidence to predict future response. Figure 10 shows the predicted downhole pressure decline if the production rate were maintained for six months at a constant production rate of $q =$ 30,000 sep bbls/day without regard to the declining surface pressure.

Figure 11 presents the results of the updated simulation in a different form. The 53 wellbottom pressures denoted by (•) in Figure 11 are the simulated "instantaneous" buildup pressures at 15,100 feet. These calculated values correspond to the 53 shutin periods during the simulated production history (see Figure 1). The "instantaneous" values are computed at $\Delta t \sim 6$ min. Figure 11 also shows the predicted wellbottom flowing pressures if the Gladys McCall well were to be produced subsequent to the 92-hour test at a constant rate of 30,000 sep bbls/day (denoted in Figure 11 by $p_{WB,\ flowing}$). We note that after six months this curve has not attained a constant slope that would indicate semi-steady state flow. For a homogeneous reservoir of volume equal to that used in our simulation model the flowing pressure under semi-steady state conditions would decline according to

$$\frac{dp_{wf}}{dQ} = \frac{B}{C_T V_p} = \frac{0.984}{(6.27 \times 10^{-6})(2.57 \times 10^{9})} = 63 \text{ psi}/10^{6} \text{sep bbls}$$

A line of this slope is shown in Figure 11 for comparison purposes.

An approximation to the associated flowing wellhead pressure can be obtained by subtracting the wellbore pressure drop (Δp_{WB}) from the predicted flowing wellbottom pressure. The S-CUBED WELBOR model, calibrated using measurements during the 79-hour test, can provide an estimate for Δp_{WB} for various flow rates. Although the value of Δp_{WB} declines as bottomhole pressure declines, an approximation at 30,000 sep bbls/day is $\Delta p_{WB} \sim 8{,}520$ psi. In Figure 11 the corresponding wellhead pressure decline prediction is denoted by $p_{WH,\ flowing}$.

During the simulated history-match calculations there were four brief shutin periods when the well was flowing at approximately 30,000 sep bbls/day. The computed sandface pressure increase from just prior to shutin to just after shutin were between 611 and 673 psi. A rough estimate of the "instantaneous" buildup pressures at 15,100 feet that would be anticipated if the projected production at 30,000 sep bbls/day were interrupted by brief shutin periods (obtained by adding 650 psi to $p_{WB,\ flowing}$) is shown in Figure 11 by the curve denoted by $p_{WB}]_{\Delta t=0+}$. This curve represents the predicted extrapolation of the points denoted by (•). To obtain the corresponding estimate for the anticipated "instantaneous" wellhead pressures requires adding both the ~ 650 psi and the frictional pressure loss ($\Delta p_{fric} = \Delta p_{WB} - \Delta p_{hydr}$) at q =30,000 sep bbls/day to $p_{WH,\ flowing}$:

$$p_{WH}\Big]_{\Delta t=0+} \sim p_{WH,\ flowing} + 650 + (8520 - 6626)$$

$$= p_{WH,\ flowing} + 2544 \text{ psi}$$

This estimate involves three approximations and may be in error by 100 psi or more. No curve is included in Figure 11 for this estimate.

4. Conclusions

In summary, we conclude that

- A reservoir model with elastic rock properties and recharge from overlying/underlying sands provides an excellent match to the production history of the Gladys McCall No. 1 well.

- The model also provides an excellent match to the detailed downhole pressure buildup measurements made during the Reservoir Limits Test and the 79-hour and 92-hour buildup tests.

- The model can be used to predict future reservoir response wellbottom pressures and, in conjunction with wellbore model calculations, wellhead pressures.

- The current geologic-understanding of the Gladys McCall reservoir is consistent with recharge of Sand Zone No. 8 by crossflow from overlying/underlying sands.

- In spite of this agreement, the described reservoir model is not uniquely determined and reservoir pressure maintenance by a remote gas cap or by nonlinear rock properties can not be ruled out at present.

- Once production testing of the well nears completion, a wireline spinner test should be run in the Gladys McCall No. 1 well to determine fluid entry locations and the extent of any plugging of the perforations.

TABLE 1

ANALYSIS OF SAND ZONE NO. 8 DOWNHOLE BUILDUP PRESSURE MEASUREMENTS

	R. L. Test	79-Hr Test		92-Hr Test	
kH (md-ft)	44,020	23,930		23,080	
	H = 332 ft	H = 332 ft	H = 207 ft	H = 332 ft	H = 207 ft
k(md)	133	72.1	116	69.5	111
s	+2.55	+6.13	+5.89	+3.11	+2.87
Δp_s(psi)*	35	170	164	61	56

* Calculated for production rate at time of shutin (sep bbls/day):

	R. L. Test	79-Hr Test	92-Hr Test
	14,162	15,438	10,470

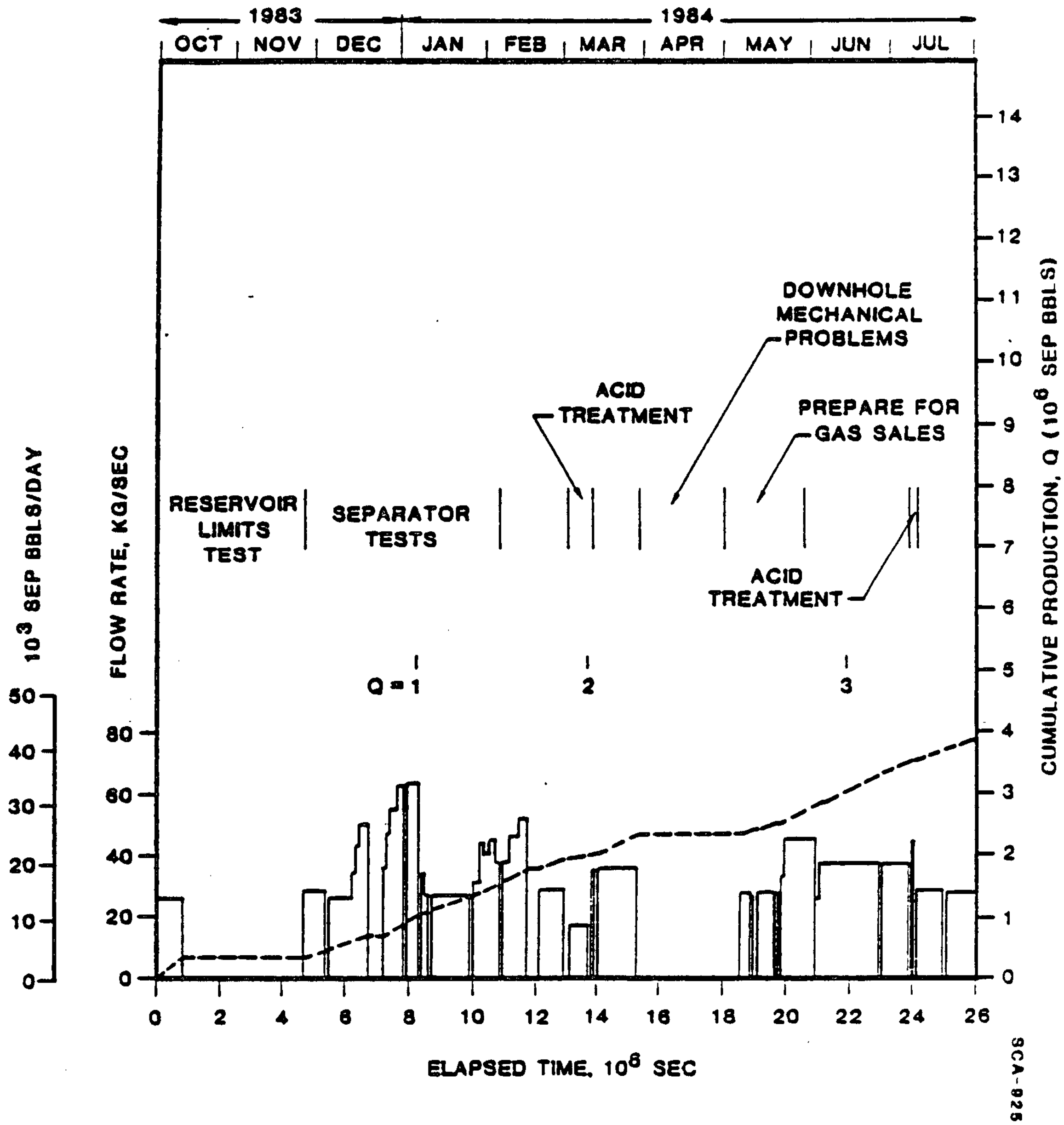


Figure 1a.

Figure 1. Gladys McCall well production history through February 8, 1986.

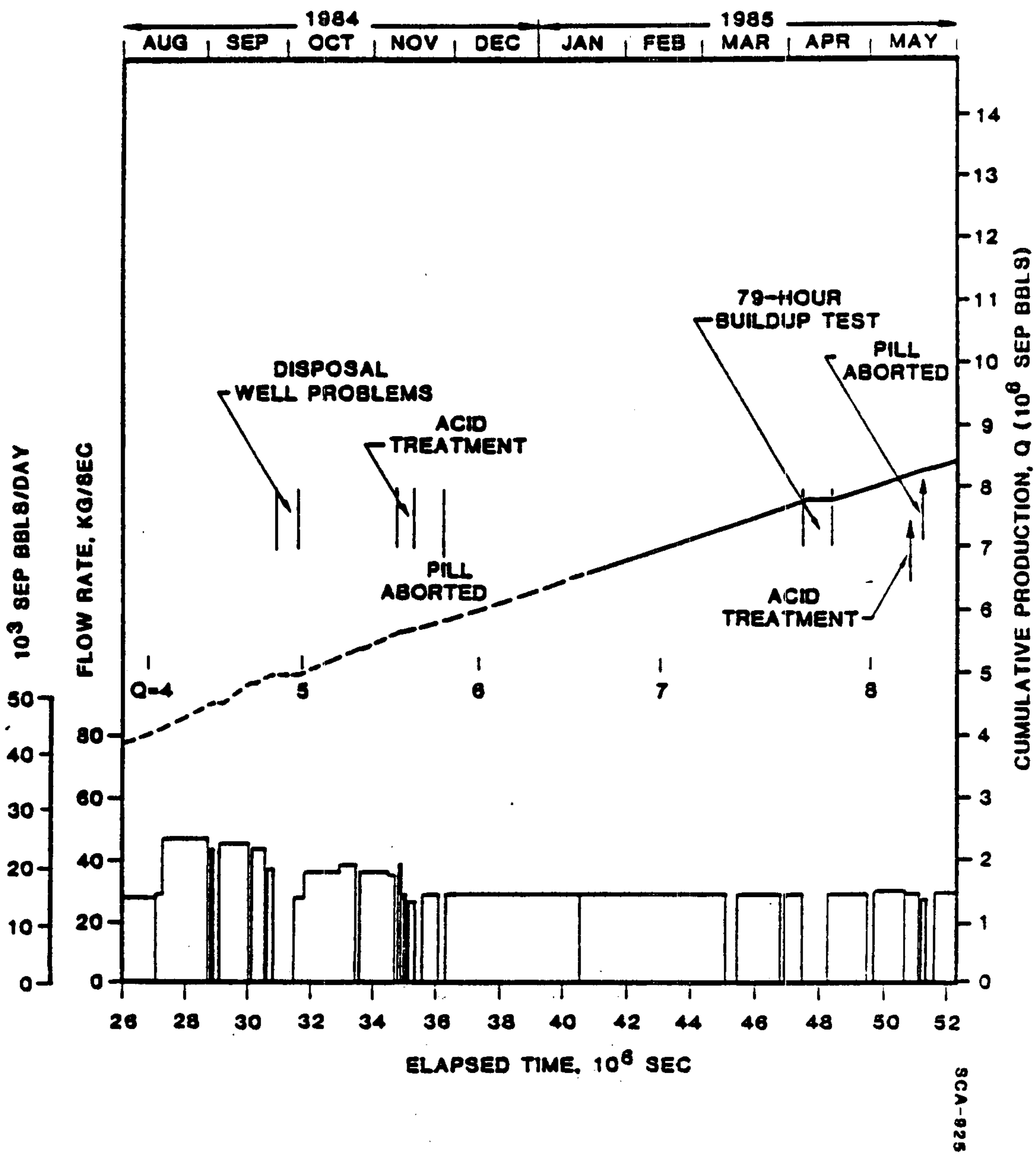
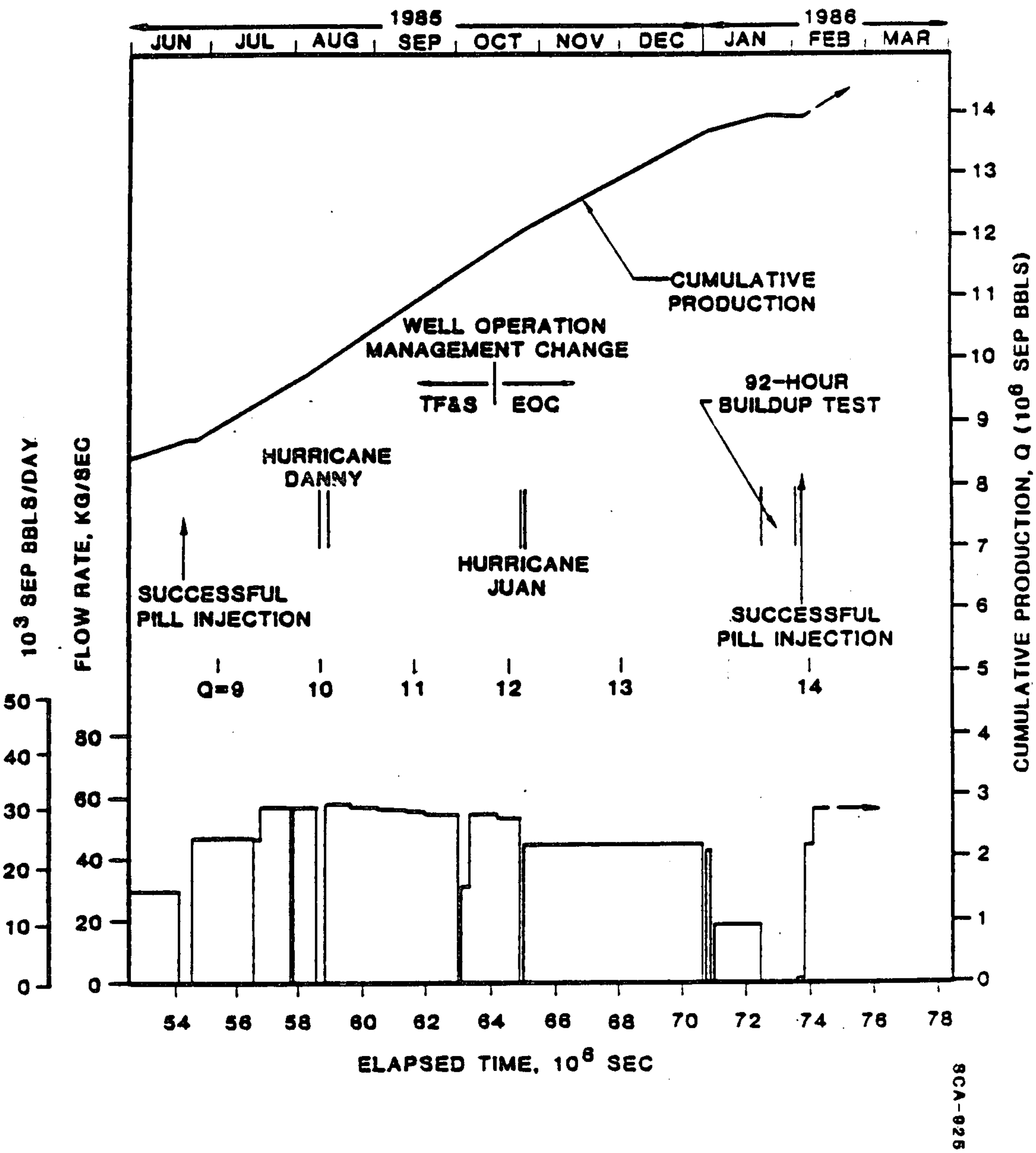

1984
1985
AUG
SEP
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
DISPOSAL
WELL PROBLEMS
ACID
TREATMENT
PILL
ABORTED
79-HOUR
BUILDUP TEST
PILL
ABORTED
ACID
TREATMENT
Q-4
5
6
7
8
10^3 SEP BBLS/DAY
FLOW RATE, KG/SEC
CUMULATIVE PRODUCTION, Q (10^6 SEP BBLS)
ELAPSED TIME, 10^6 SEC
SCA-925

Figure 1b.



1985
1986
JUN
JUL
AUG
SEP
OCT
NOV
DEC
JAN
FEB
MAR
CUMULATIVE PRODUCTION
WELL OPERATION MANAGEMENT CHANGE
TF&S
EOC
92-HOUR BUILDUP TEST
HURRICANE DANNY
HURRICANE JUAN
SUCCESSFUL PILL INJECTION
SUCCESSFUL PILL INJECTION
Q=9
10
11
12
13
14
10^3 SEP BBLS/DAY
FLOW RATE, KG/SEC
CUMULATIVE PRODUCTION, Q (10^6 SEP BBLS)
ELAPSED TIME, 10^6 SEC
SCA-925

Figure 1c.

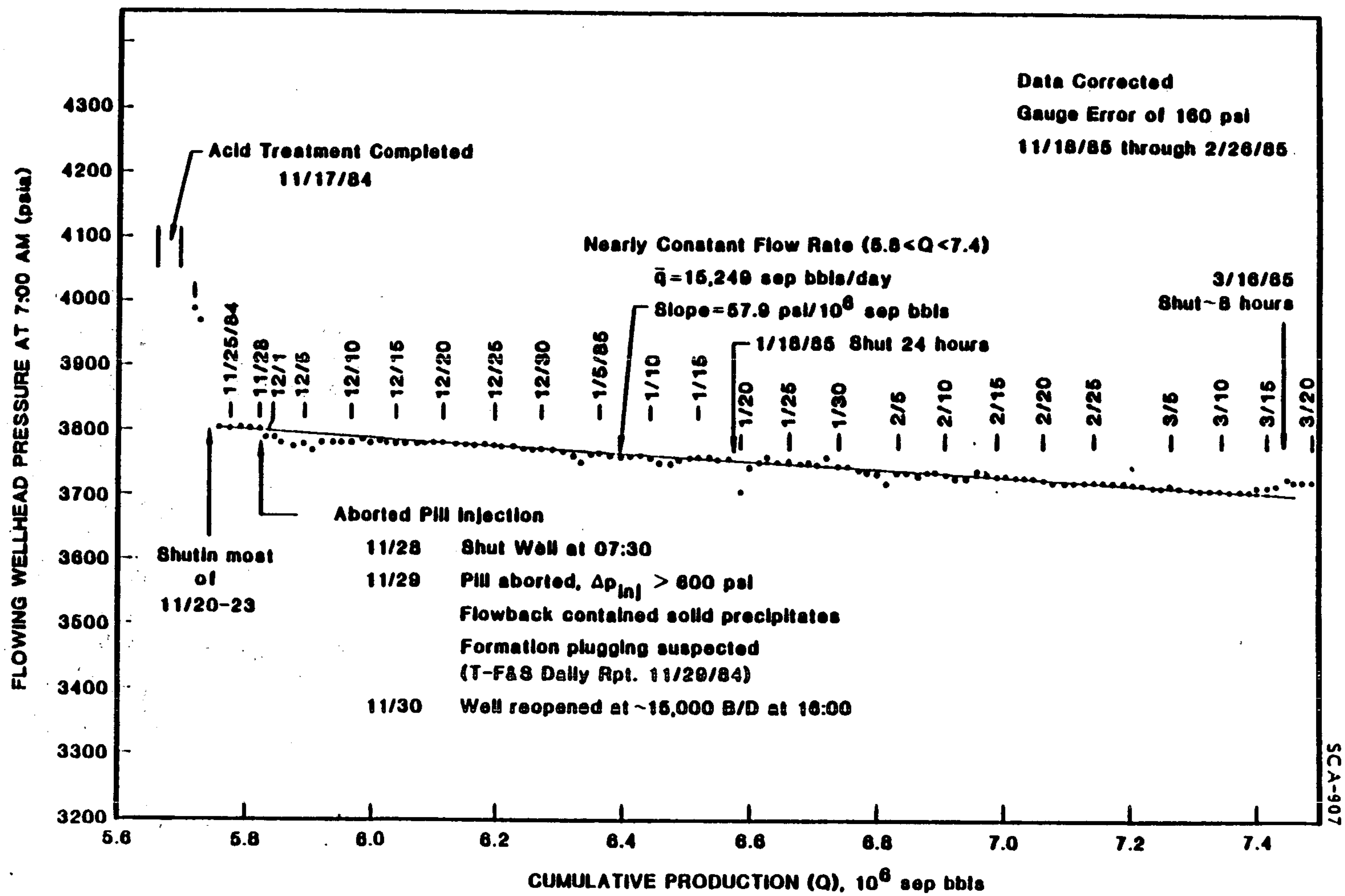
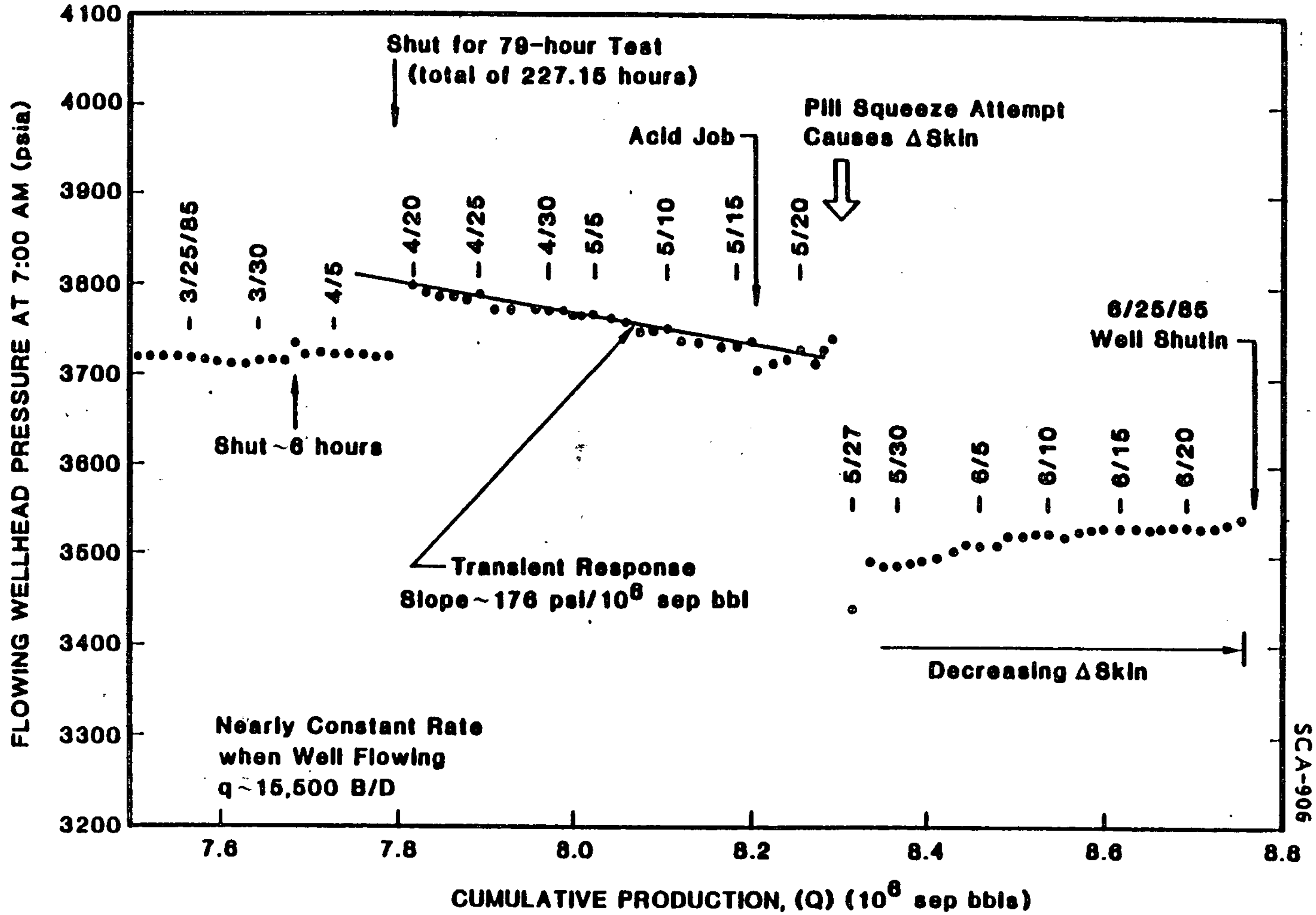


Figure 2a.

Figure 2. Flowing wellhead pressures (recorded at surface tubing of Gladys McCall No. 1 well) at 7:00 a.m. of indicated days.



FLOWING WELLHEAD PRESSURE AT 7:00 AM (psia)
CUMULATIVE PRODUCTION, (Q) (10^6 sep bbls)
4100
4000
3900
3800
3700
3600
3500
3400
3300
3200
7.6
7.8
8.0
8.2
8.4
8.6
8.8
Shut for 79-hour Test
(total of 227.15 hours)
Acid Job
Pill Squeeze Attempt
Causes Δ Skin
3/25/85
3/30
4/5
4/20
4/25
4/30
5/5
5/10
5/15
5/20
5/27
5/30
6/5
6/10
6/15
6/20
6/25/85
Well Shutin
Shut ~6 hours
Transient Response
Slope ~ 176 psi/10^6 sep bbl
Decreasing Δ Skin
Nearly Constant Rate
when Well Flowing
q ~ 15,500 B/D
SCA-906

Figure 2b.

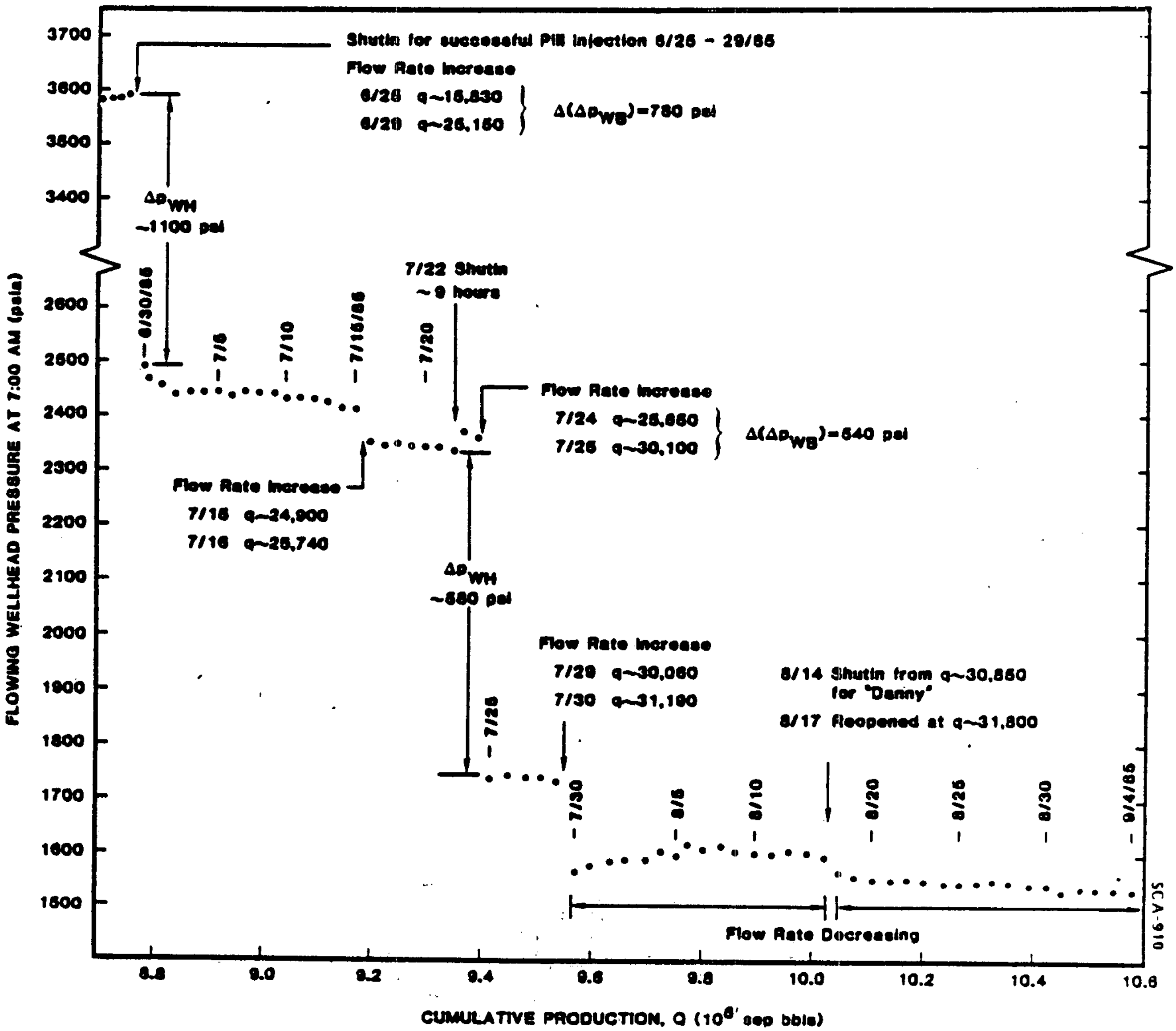
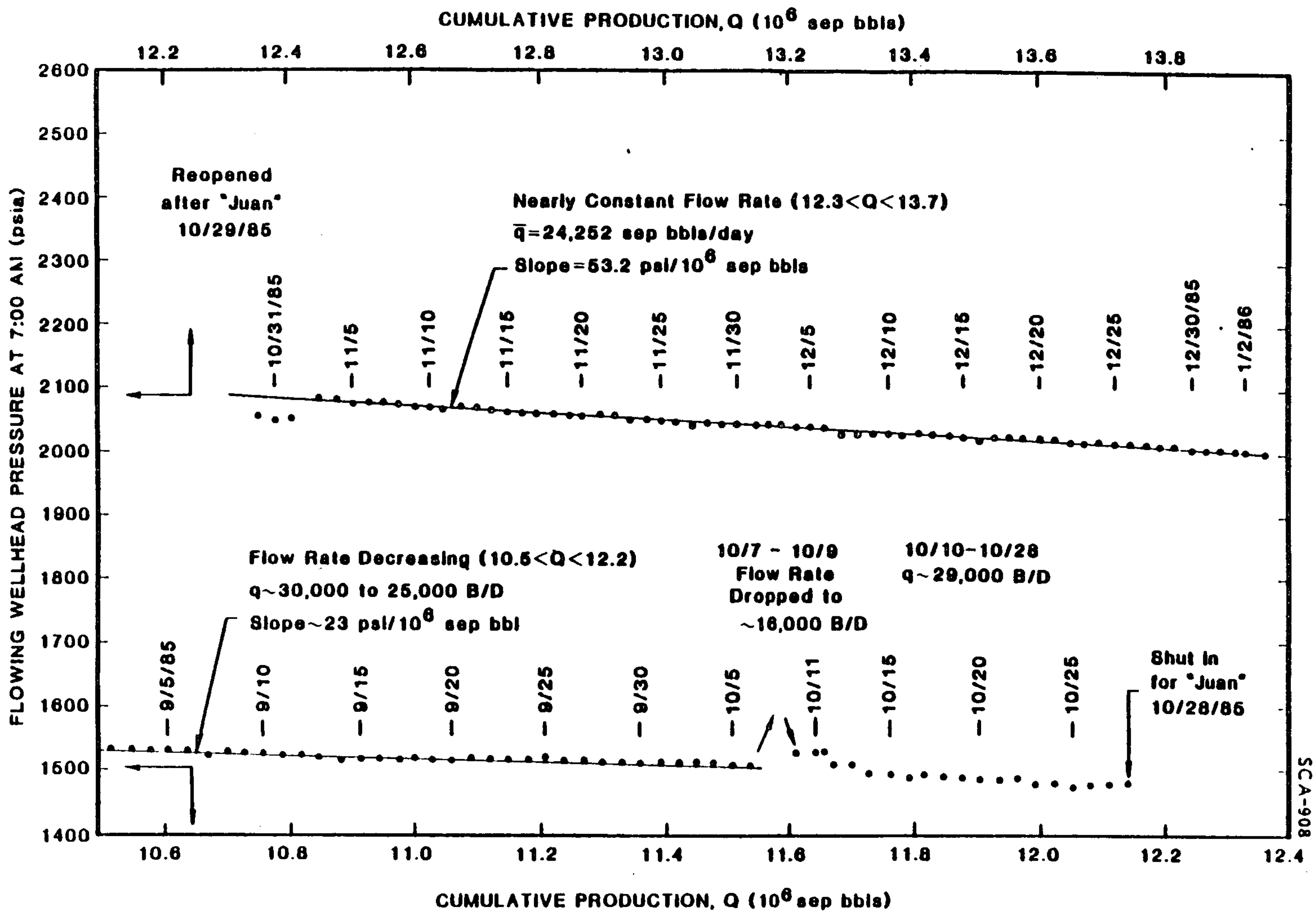

Shutin for successful Pill injection 6/25 - 29/85
Flow Rate Increase
6/25 q~15,830
6/29 q~25,150
Δ(Δp_WB)=750 psi
Δp_WH ~1100 psi
6/30/85
7/5
7/10
7/15/85
7/20
7/22 Shutin ~9 hours
Flow Rate Increase
7/24 q~25,850
7/25 q~30,100
Δ(Δp_WB)=540 psi
Flow Rate Increase
7/15 q~24,900
7/16 q~25,740
Δp_WH ~580 psi
Flow Rate Increase
7/29 q~30,060
7/30 q~31,190
8/14 Shutin from q~30,850 for "Danny"
8/17 Reopened at q~31,800
7/25
7/30
8/5
8/10
8/20
8/25
8/30
9/4/85
Flow Rate Decreasing
FLOWING WELLHEAD PRESSURE AT 7:00 AM (psia)
CUMULATIVE PRODUCTION, Q (10⁶ sep bbls)
SCA-910

Figure 2c.



CUMULATIVE PRODUCTION, Q (10^6 sep bbls)
12.2
12.4
12.6
12.8
13.0
13.2
13.4
13.6
13.8
2600
2500
2400
2300
2200
2100
2000
1900
1800
1700
1600
1500
1400
FLOWING WELLHEAD PRESSURE AT 7:00 AM (psia)
Reopened after "Juan" 10/29/85
Nearly Constant Flow Rate (12.3<Q<13.7)
q̄=24,252 sep bbls/day
Slope=53.2 psi/10^6 sep bbls
10/31/85
11/5
11/10
11/15
11/20
11/25
11/30
12/5
12/10
12/15
12/20
12/25
12/30/85
1/2/86
Flow Rate Decreasing (10.5<Q<12.2)
q~30,000 to 25,000 B/D
Slope~23 psi/10^6 sep bbl
10/7 - 10/9 Flow Rate Dropped to ~16,000 B/D
10/10-10/28 q~29,000 B/D
9/5/85
9/10
9/15
9/20
9/25
9/30
10/5
10/11
10/15
10/20
10/25
Shut in for "Juan" 10/28/85
10.6
10.8
11.0
11.2
11.4
11.6
11.8
12.0
12.2
12.4
CUMULATIVE PRODUCTION, Q (10^6 sep bbls)
SCA-908

Figure 2d.

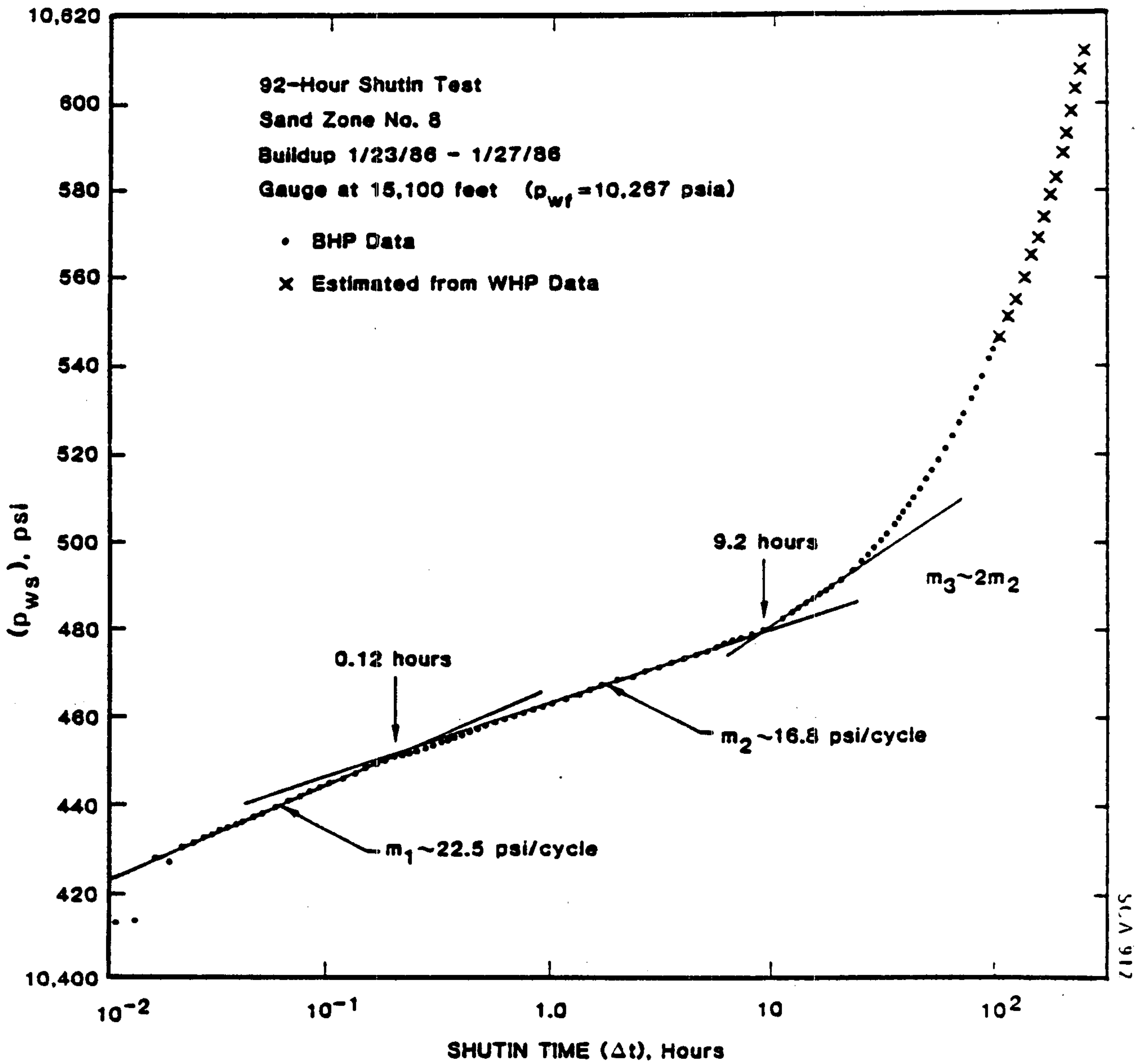


Figure 3. Pressure buildup semi-log plot for 92-hour shutin test of Sand Zone No. 8.

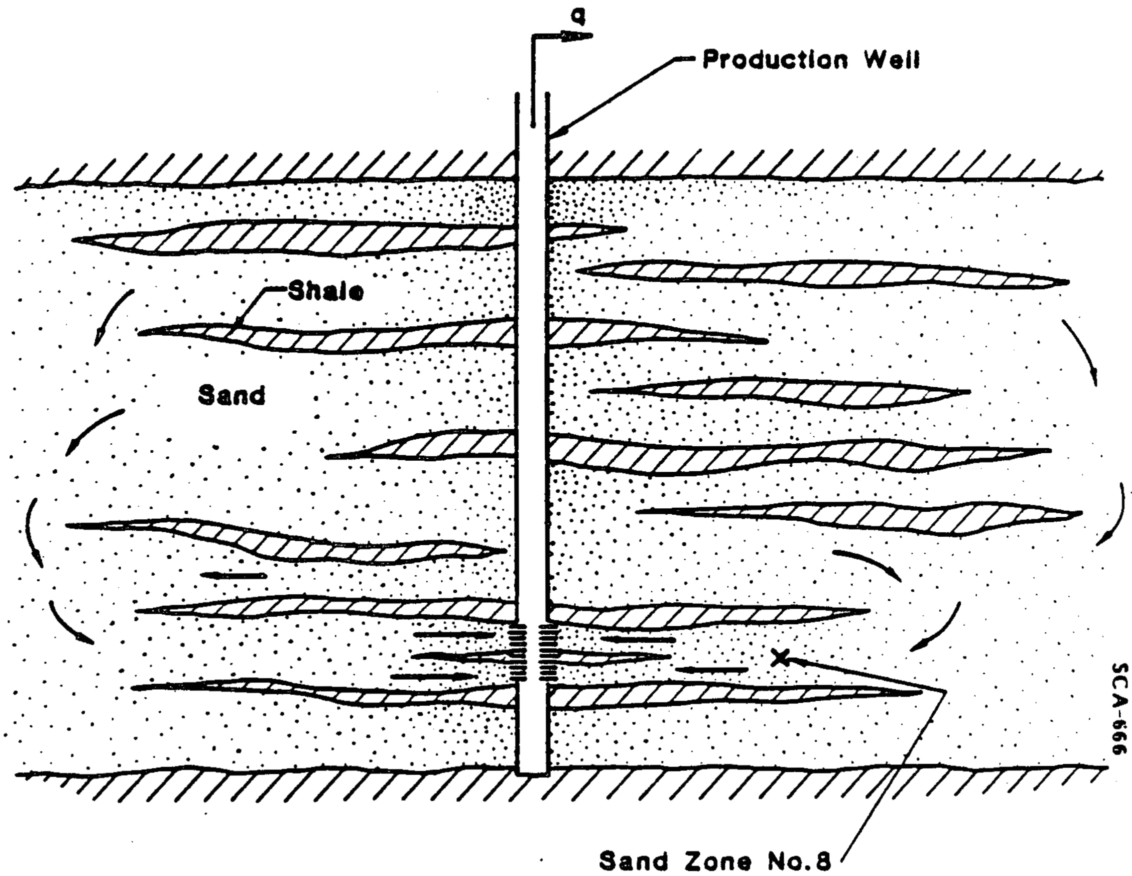


Figure 4. Conceptual model of reservoir produced by Sand Zone No. 8.

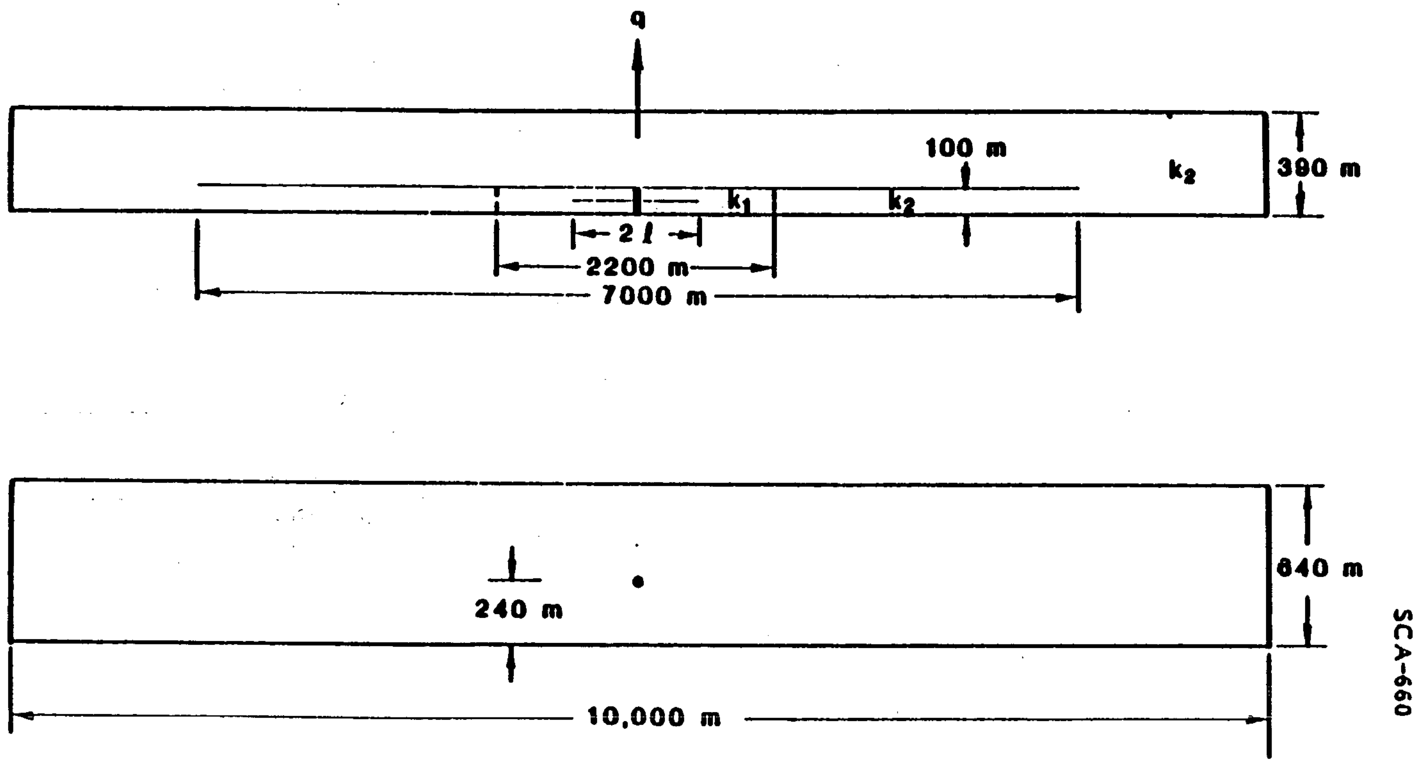


Figure 5. Model for Gladys McCall reservoir based on assumption that pressure maintenance due to crossflow from overlying/underlying sands (k_1 = 160 md; k_2 = 20 md; ℓ = 200 m).

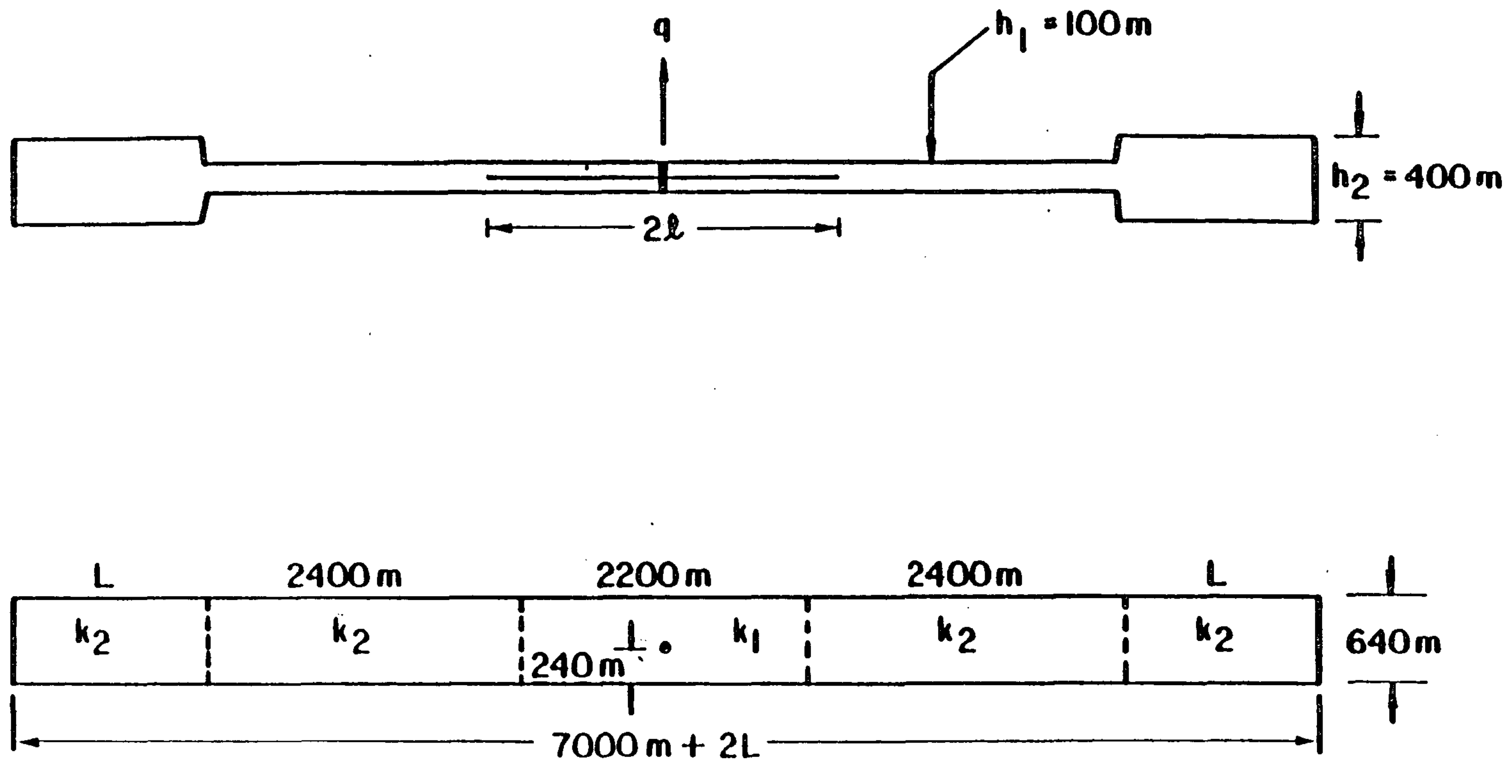


Figure 6. Numerical equivalent model used in Gladys McCall reservoir production history-match simulation (L = 4000 m; k_1 = 160 md; k_2 = 20 md).

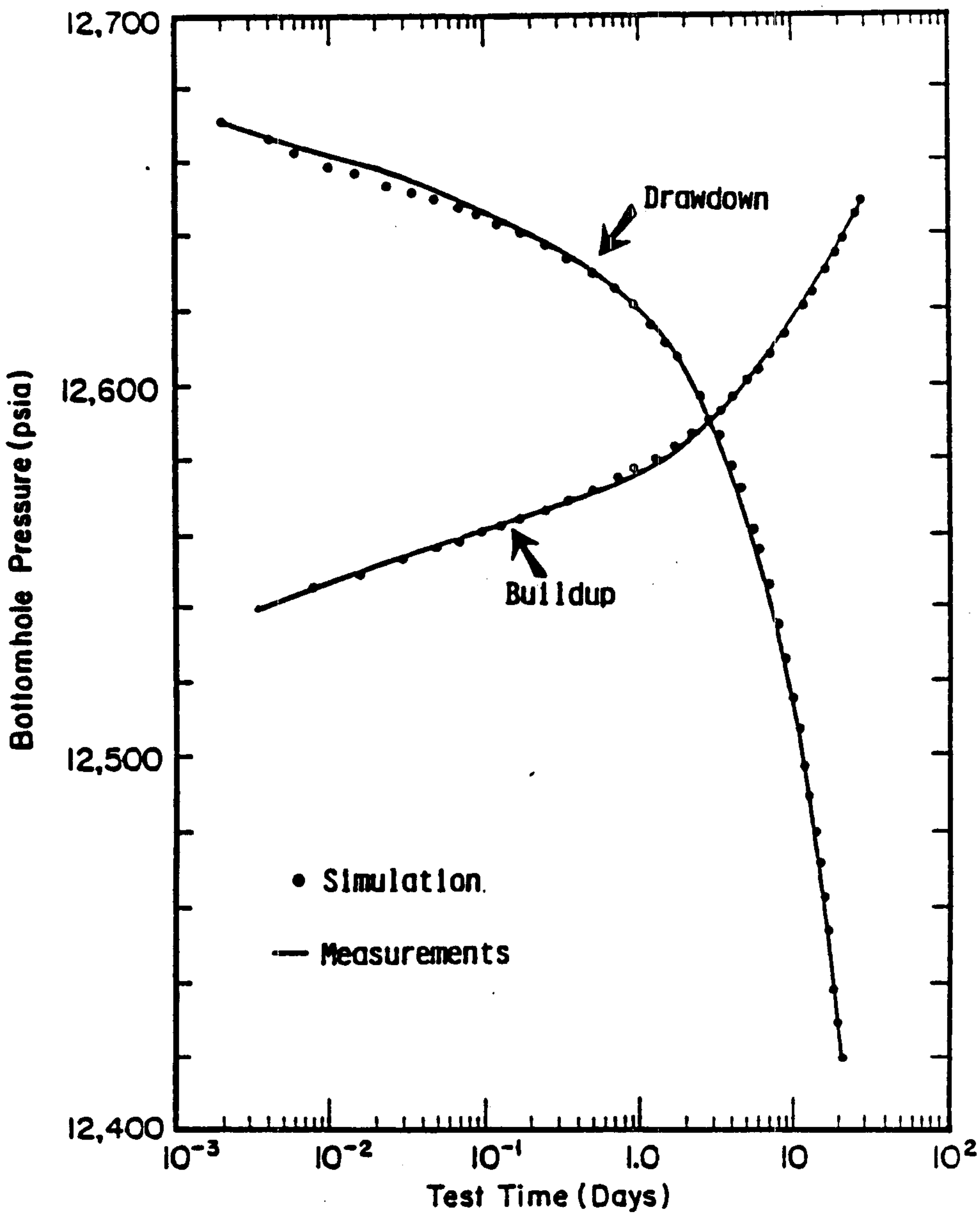


Figure 7. Comparison of bottomhole pressures calculated with simulation model and values measured during drawdown/buildup portions of Reservoir Limits Test.

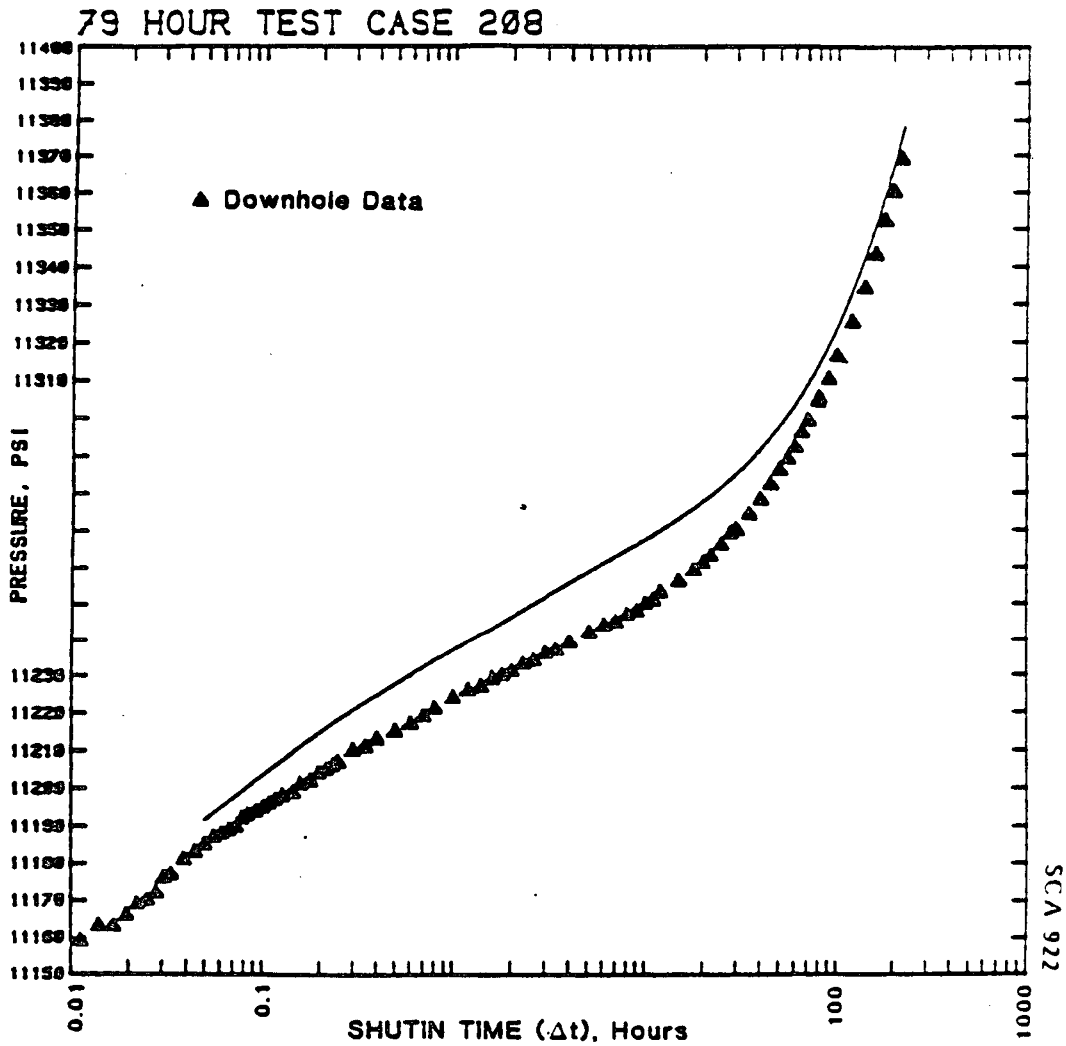


Figure 8. Comparison of bottomhole pressures calculated with simulation model and values measured during 79-hour buildup test.

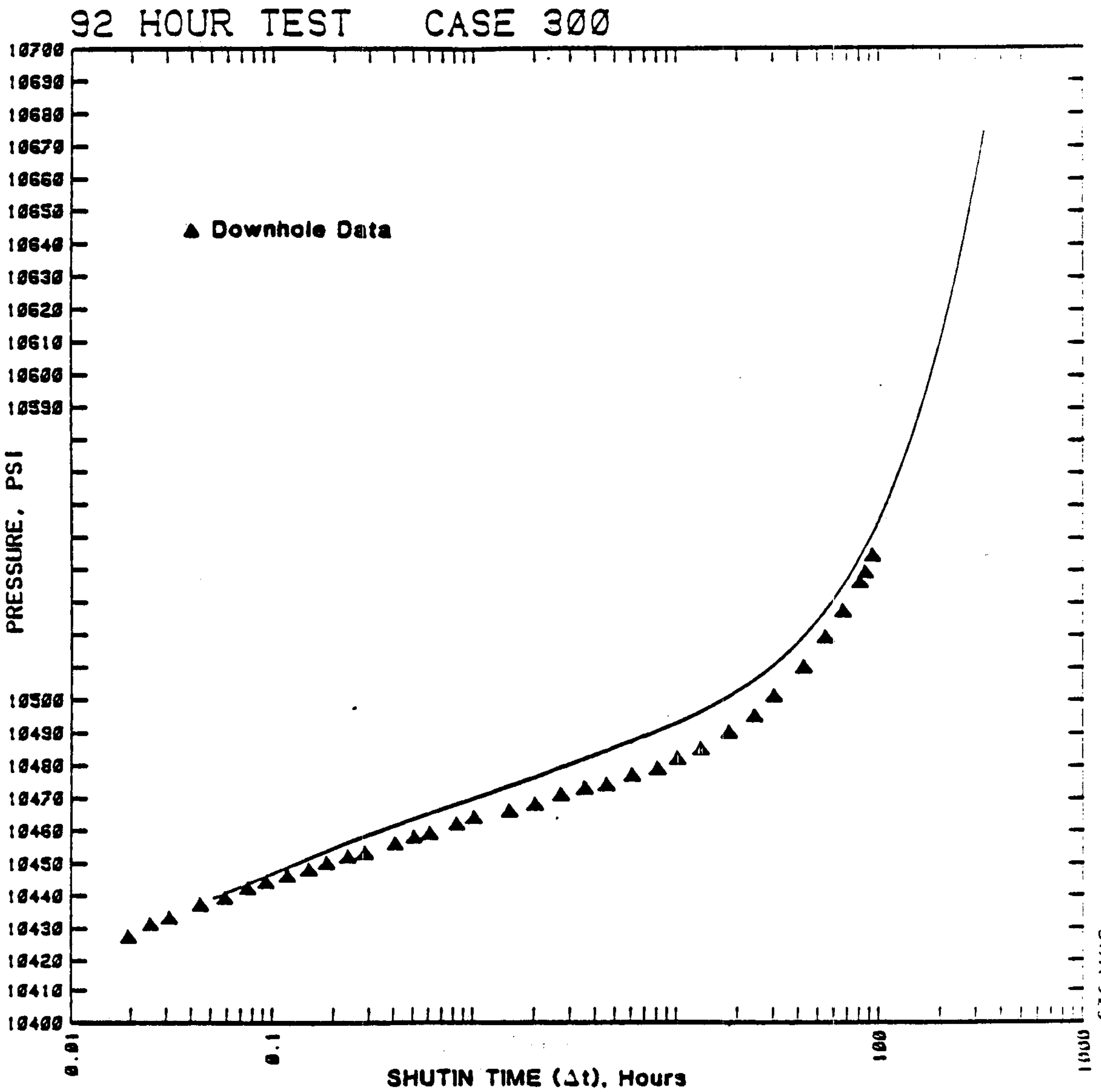


Figure 9. Comparison of bottomhole pressures calculated with simulation model and values measured during 92-hour buildup test.

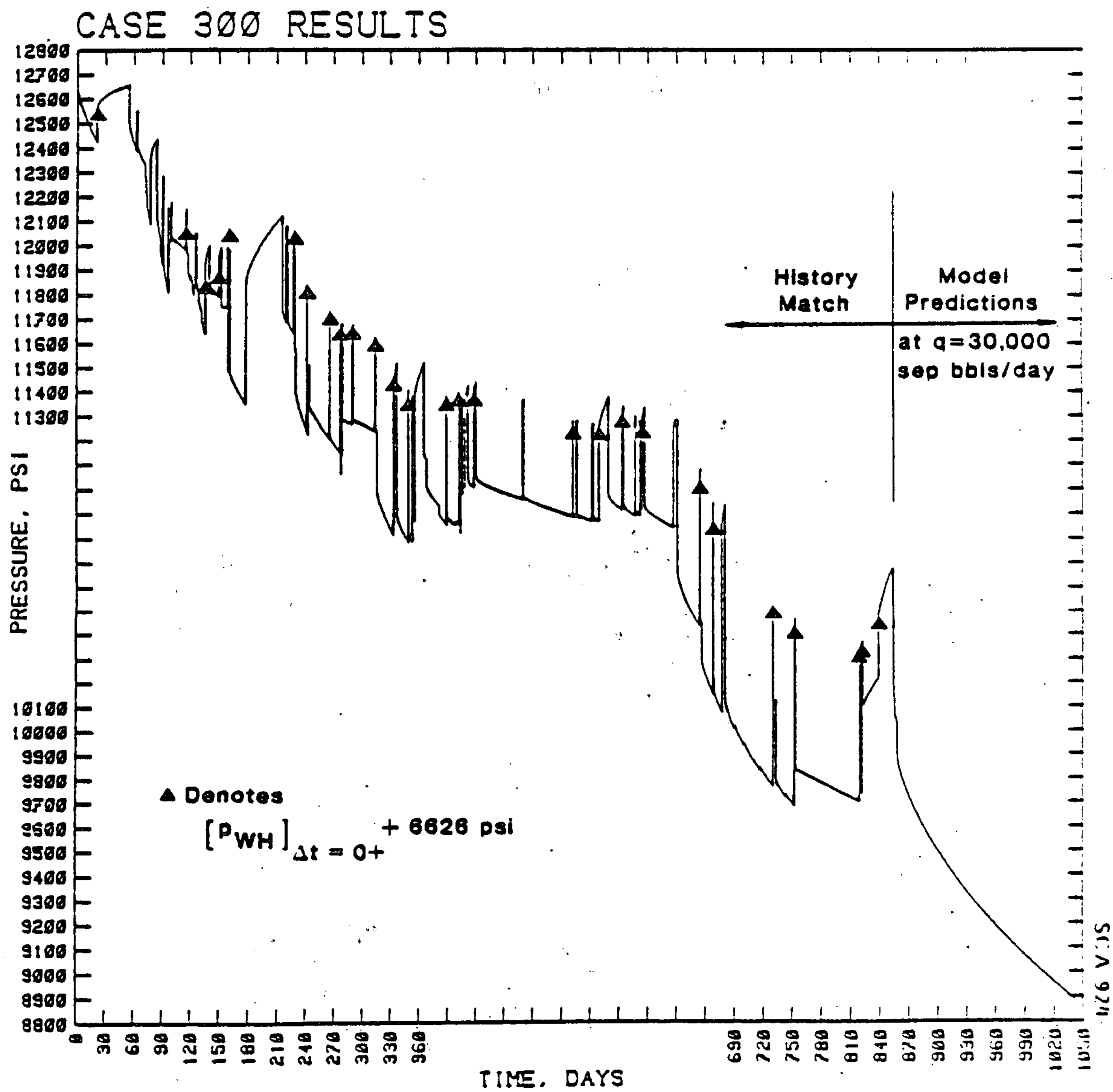


Figure 10. Comparison of simulated bottomhole pressures with values estimated from "instantaneous shutin wellhead pressure measurements. Figure depicts history-match from initiation of production from Sand Zone No. 8 through the 92-hour buildup test and model predictions.

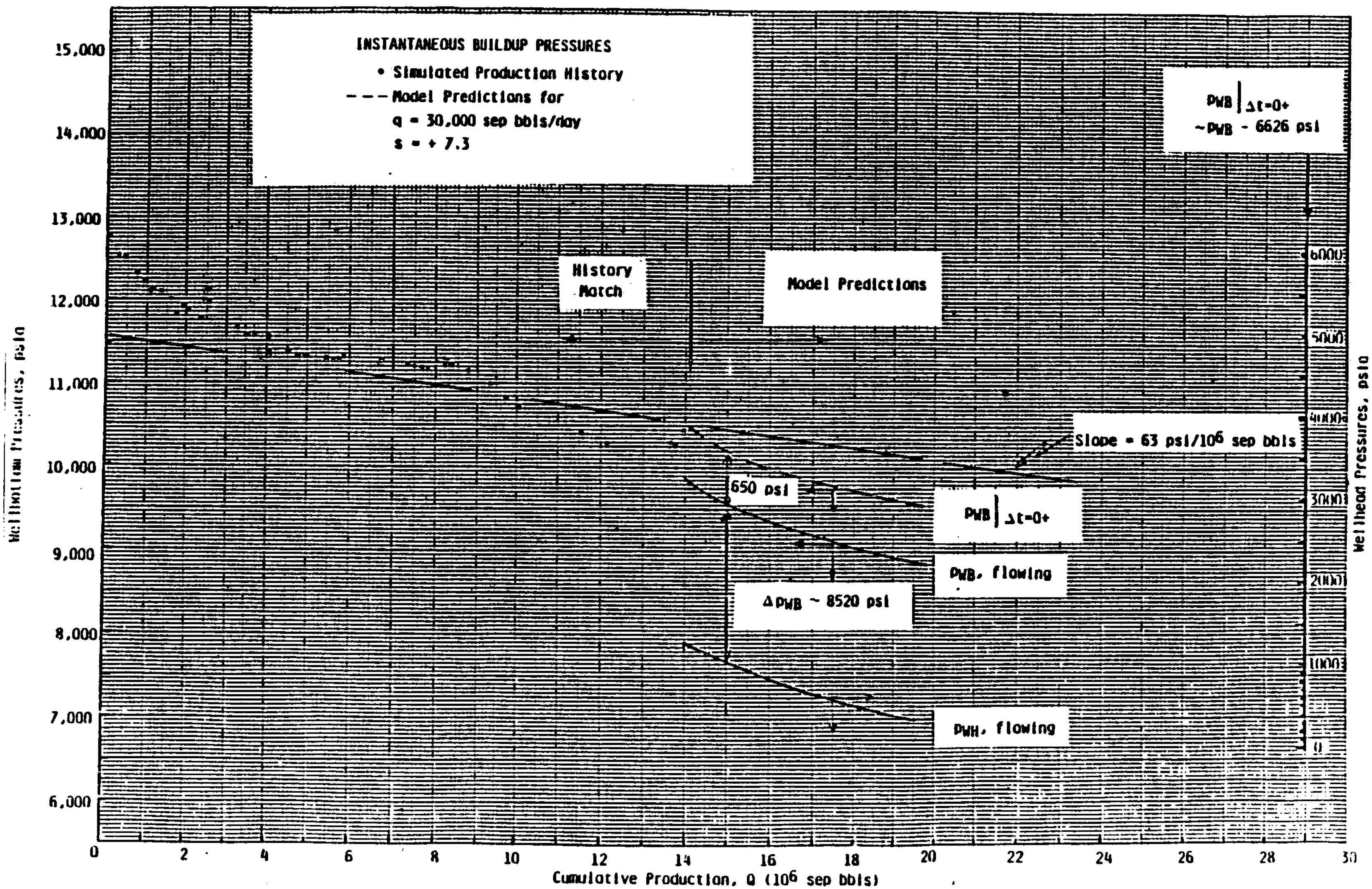


Figure 11. Simulated values of bottomhole instantaneous buildup pressures over production history (from initiation through the 92-hour test) of Sand Zone No. 8 and predicted values if subsequently produced at 30,000.

G. APPENDIX 7

PLEASANT BAYOU REWORK INCLUDING DRAWINGS OF HARDWARE AND BOTTOM HOLE PRESSURE MEASUREMENT

T. MEAHL - EOC

PLEASANT BAYOU N° 2

BRAZORIA CO., TX.

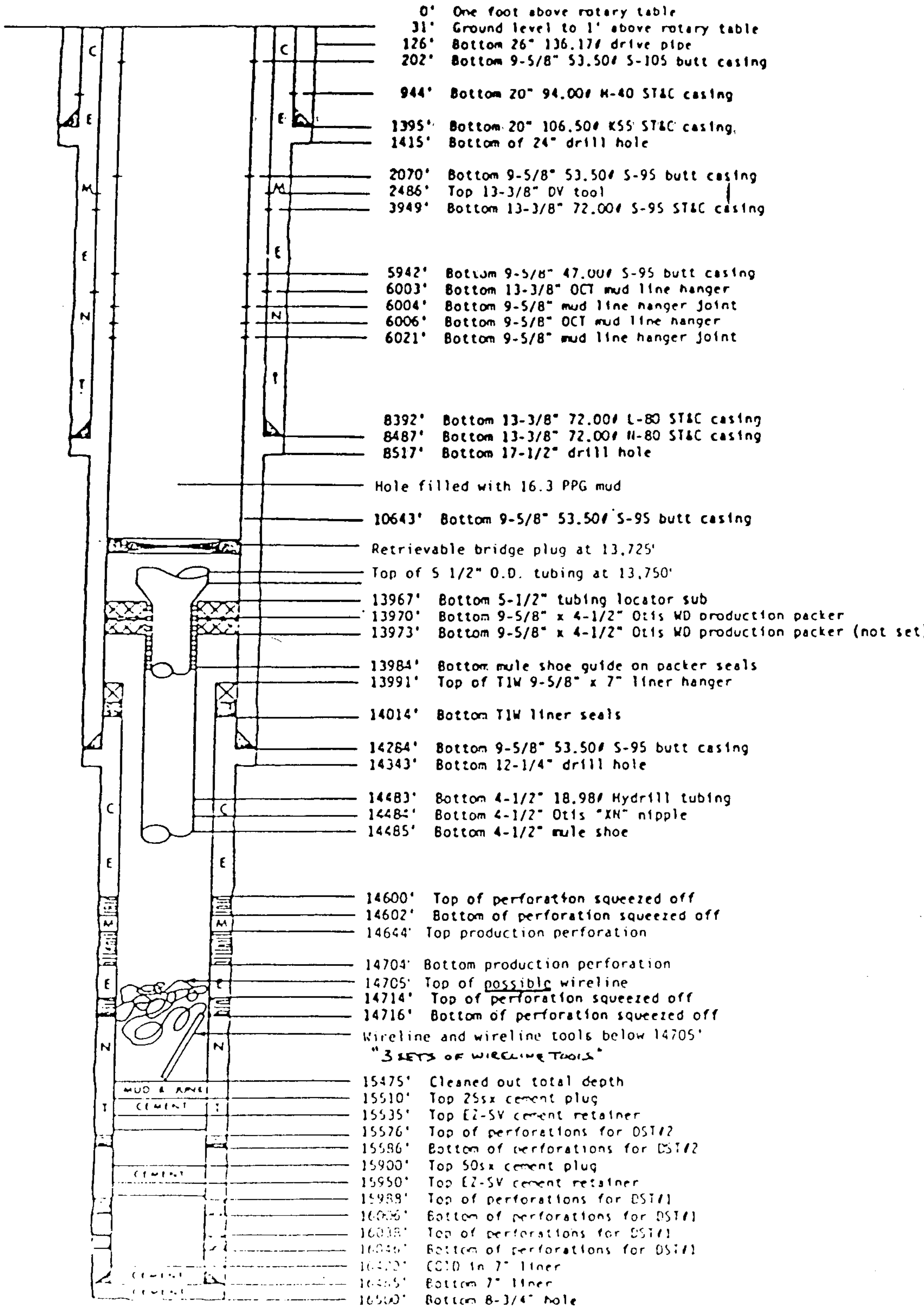
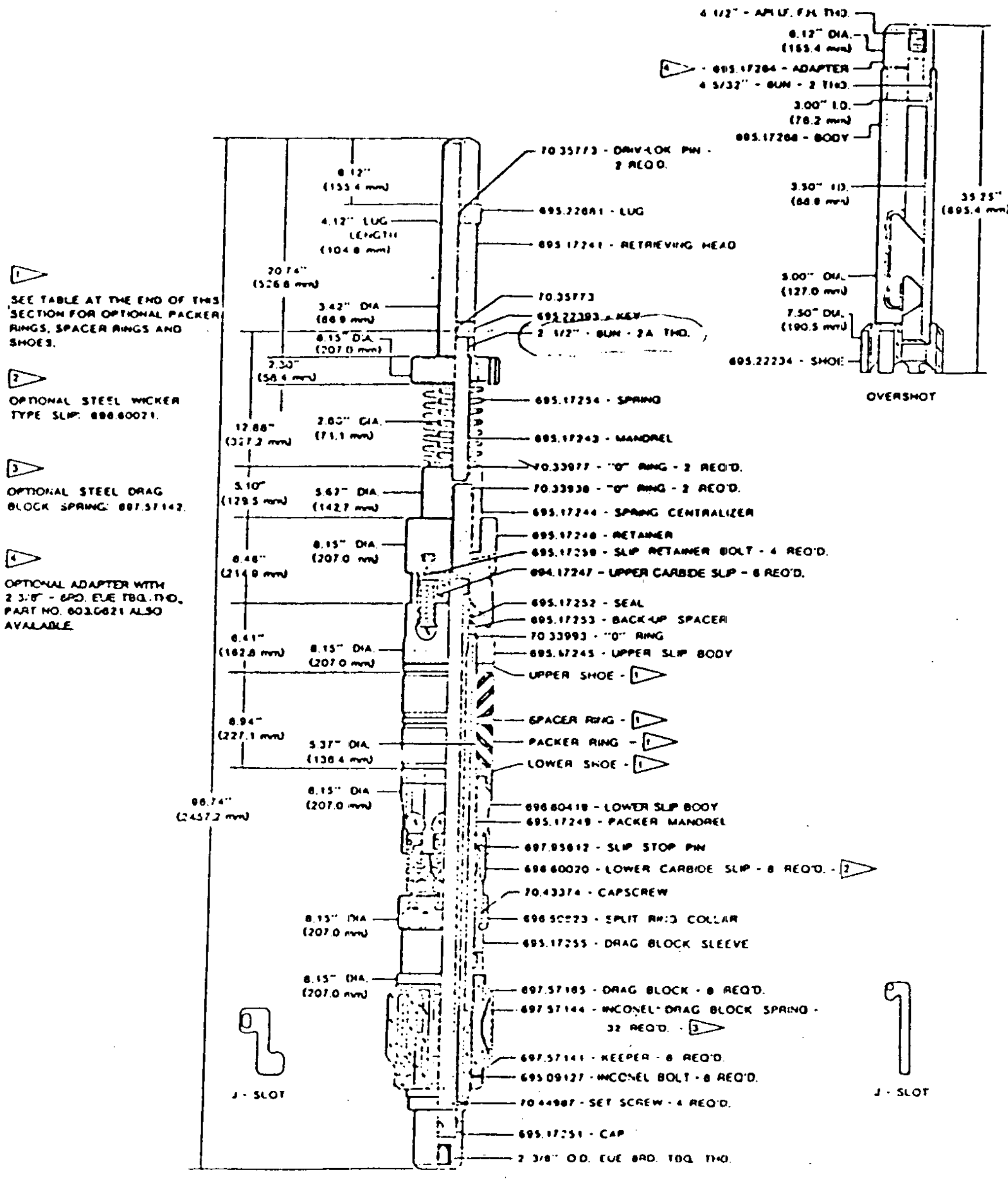


FIGURE 1.

CONDITION OF No. 2 WELL 8/15/83

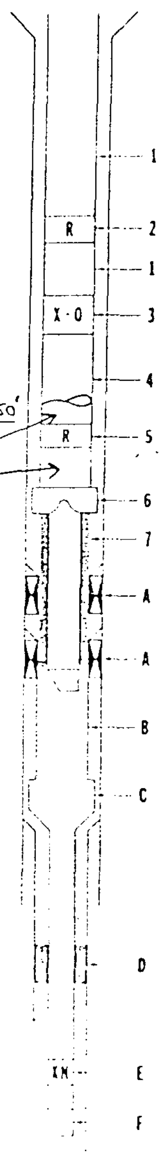


MODEL 3 PACKER TYPE
RETRIEVABLE BRIDGE PLUG
9 5/8" - 29.3 - 53.5# - 695.1724
ASSEMBLY NOT AVAILABLE
SPARE PARTS AVAILABLE ON SPECIAL ORDER

FIGURE 2.

BRIDGE PLUG AND RETRIEVING TOOL

General Crude Oil Co.		Chocolate Bayou				Pleasant Bayou #2
Arby Trolinger	CASING	9-5/8	53#	S105	Buttress	
Brazoria TX	LINER	7"	38#	P110	TUBING WT. ON	
TUBING	UPPER	5-1/2	23#	P110	8rdABC	TYPE LATCH
	MIDDLE	5-1/2	23#	P110	FL4S	J. Weatherby, L. Moerbe 457775
	LOWER	4-1/2	18.98		FJ-Hy	Friendswood 7-3-79



Top of Tubing @ 13750'

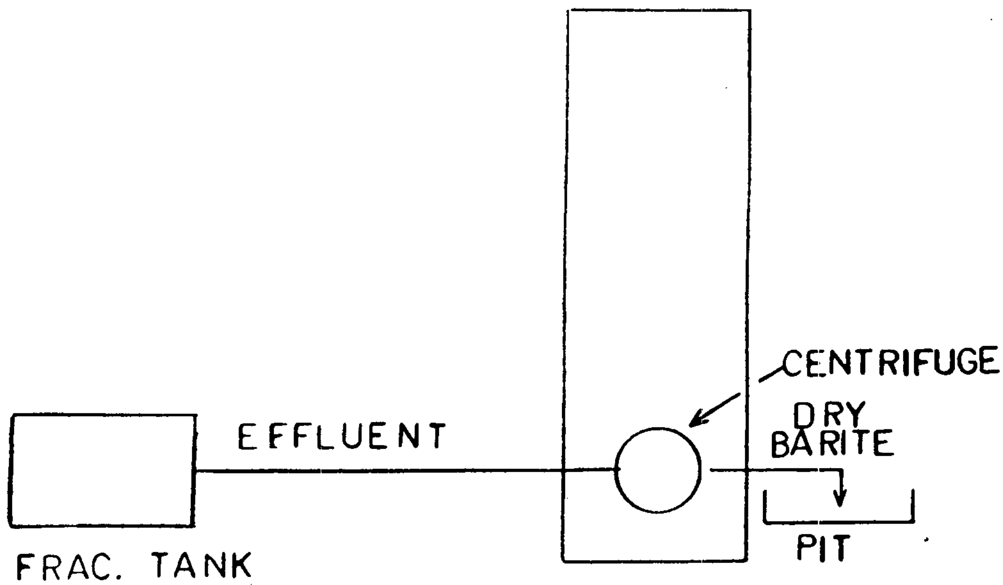
4 Jts tbg

1 Jt tbg

ITEM	DEPTH	LENGTH	JTS	DESCRIPTION	
	0	25.70		Elevation	
	25.70	1.29		Hanger	
1	26.99	5001.10	128	Tbg. 5½" 8rd ABC	
2	5028.09	1.95		Otis R Nipple 11R43100	4.313
1	5030.04	2006.44	54	Tbg. As Above	
3	7036.48	34.70	1	X-over Jt. 5½ 8rd x 5½ FL4S	
4	7071.18	6843.08	163	Tbg. 5½" FL4S	
5	13914.26	1.29		Otis R Nipple 11R43100	4.313
	13915.55	42.84	1	Tbg. As Above	
	13958.39	.61		X-over 5½ FL4S x 5" 8rd	
6	13959.00	.85		Otis St. Slot Locator 212S9053	5.55 OD 5.00 ID
7	13959.85	23.92		Otis VTR Seal Assem. 212EB9012	4.98 OD
	13983.77	.50		Mule Shoe Guide	
	13984.27			End of Production String	
NOTE: Item 7, VTR Seal Assem, was tagged at 13964' DPM (~/ RKB-GL=25'					
A	13967.00	3.35		Otis WD Packer 212WD9503	8.06 OD 5.00 ID
A	13970.35	3.35		Otis WD Packer 212WD9503	8.06 OD 5.00 ID
	13973.70	.88		X-over to S.B. Receptacle	8.04 OD 5.00 ID
B	13974.58	22.50		Otis Seal Bore	6.26 OD 5.00 ID
C	13997.08	1.52		Adaptor to TIW	
	13998.60	10.90		TIW Extension	5.01 OD
D	14009.50	4.85		TIW Seals	5.50 OD
	14014.35	469.03		Tbg. 4½" 18.95# Hydril	
	14483.38	.59		X-over	5.00 OD
E	14483.97	.83		Otis "XN" Nipple 11XN3313	4.50 OD 3.313 ID
F	14484.80	.50		Mule Shoe Guide	
	14485.30				

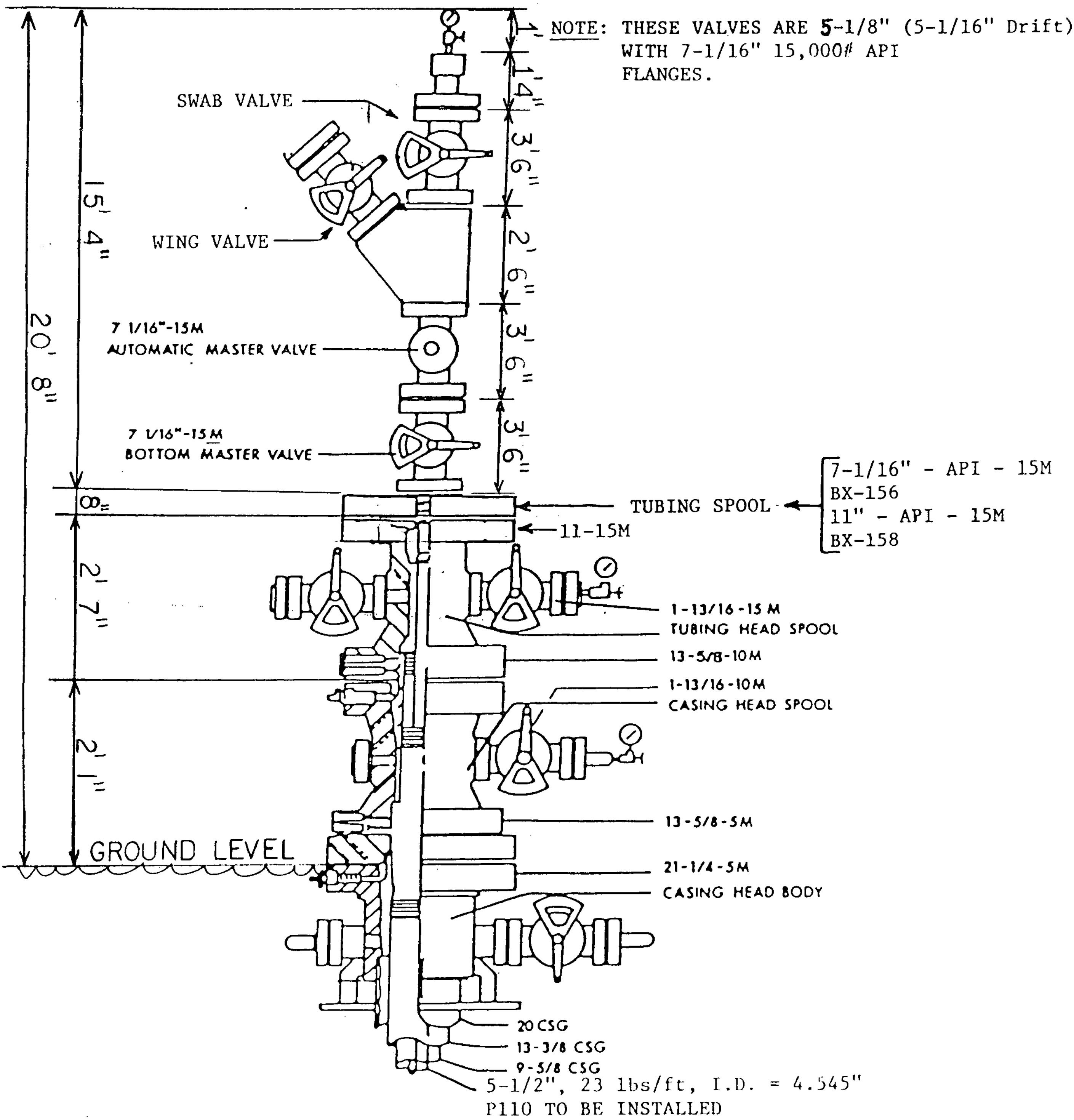
FIGURE 3.

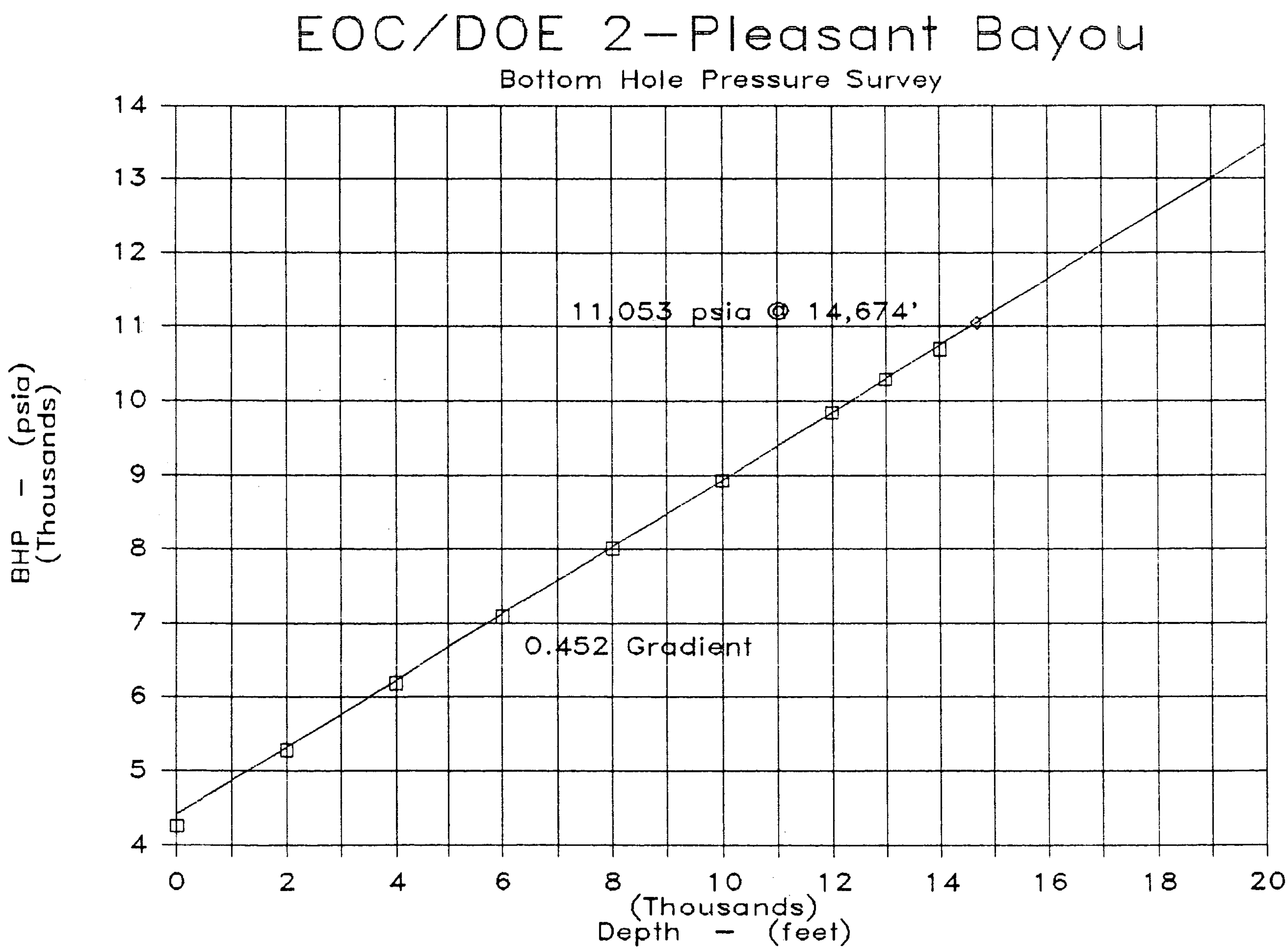
OTIS PACKER INSTALLATION REPORT



EATON OPERATING CO., INC.	
DOE/PLEASANT BAYOU	
DR. B.A. EATON	PROGRAM DIRECTOR
C.R. FEATHERSON	DEPUTY DIRECTOR
T.E. MEAHL	OVERALL EOC ENGR. & TEST. MGR.
MUD SYSTEM	

Pleasant Bayou No. 2 Wellhead Configurations 3/5/86




EOC/DOE 2-Pleasant Bayou
Bottom Hole Pressure Survey
11,053 psia @ 14,674'
0.452 Gradient
BHP - (psia)
(Thousands)
(Thousands)
Depth - (feet)
14
13
12
11
10
9
8
7
6
5
4
0
2
4
6
8
10
12
14
16
18
20

H. APPENDIX 8

EPRI EXPERIMENT STATUS INCLUDING DISCUSSION AND DIAGRAMS

E. HUGHES - EPRI

GAS/GEOTHERMAL HYBRID EXPERIMENT

Evan E. Hughes
Electric Power Research Institute
P. O. Box 10412, Palo Alto, CA 94303

BACKGROUND

Hybrid power systems that combine both gas and geothermal heat as input for power generation can produce more than 15 percent more electricity than the same amount of fuel and geothermal fluid used in separate power plants. The hybrid concept can reduce the risk and cost of developing hydrothermal resources for power generation. For geopressured resource development, the hybrid is the preferred means of energy production when electricity prices are relatively higher than gas prices. Because no field test of this concept has been performed, EPRI has joined with the U. S. Department of Energy to build and test a gas/geothermal hybrid at a geopressured well.

OBJECTIVE

The objective of the EPRI hybrid power system experiment is to evaluate the gas/geothermal hybrid concept based on design, construction and testing of a 1-MWe power system. By testing the concept at a geopressured well, EPRI is participating in the assessment of geopressured reservoirs and the technology for producing and using these geothermal resources.

SYSTEM DESCRIPTION

The figures show the hybrid power cycle as it has been designed for a test on 10,000 barrels/day of geopressured brine containing 22 standard cubic feet of gas per barrel of brine. The gas is 87 percent methane, with the balance being nearly all carbon dioxide. The first figure shows the flow rates, and the second figure shows the temperatures and pressures. The working fluid in the binary cycle is isobutane. The power output breakdown for the 1-MWe system is as follows (expressed in kWe):

Gas engine/generator	650
Binary turbine/generator	540
Pressure reduction turbine	160
Gross Power	1350
Auxiliary loads	(210)
Net Power	1140

The system to be tested includes all the equipment needed to obtain the advantage of a hybrid cycle over separate combustion and geothermal cycles. However, due to the limitation imposed by the amount of gas that is supplied with the geopressured brine, the heat from the exhaust gas of the engine contributes a smaller fraction of the binary cycle heat supply than will be the case in optimized hydrothermal applications. For hydrothermal applications at a 280°F goethermal fluid temperature, the gas supply would be set so that exhaust heat would do all the boiling of the working fluid and, as a result, the power output due to the gas engine would be twice that of the binary turbine.

ACCOMPLISHMENTS TO DATE

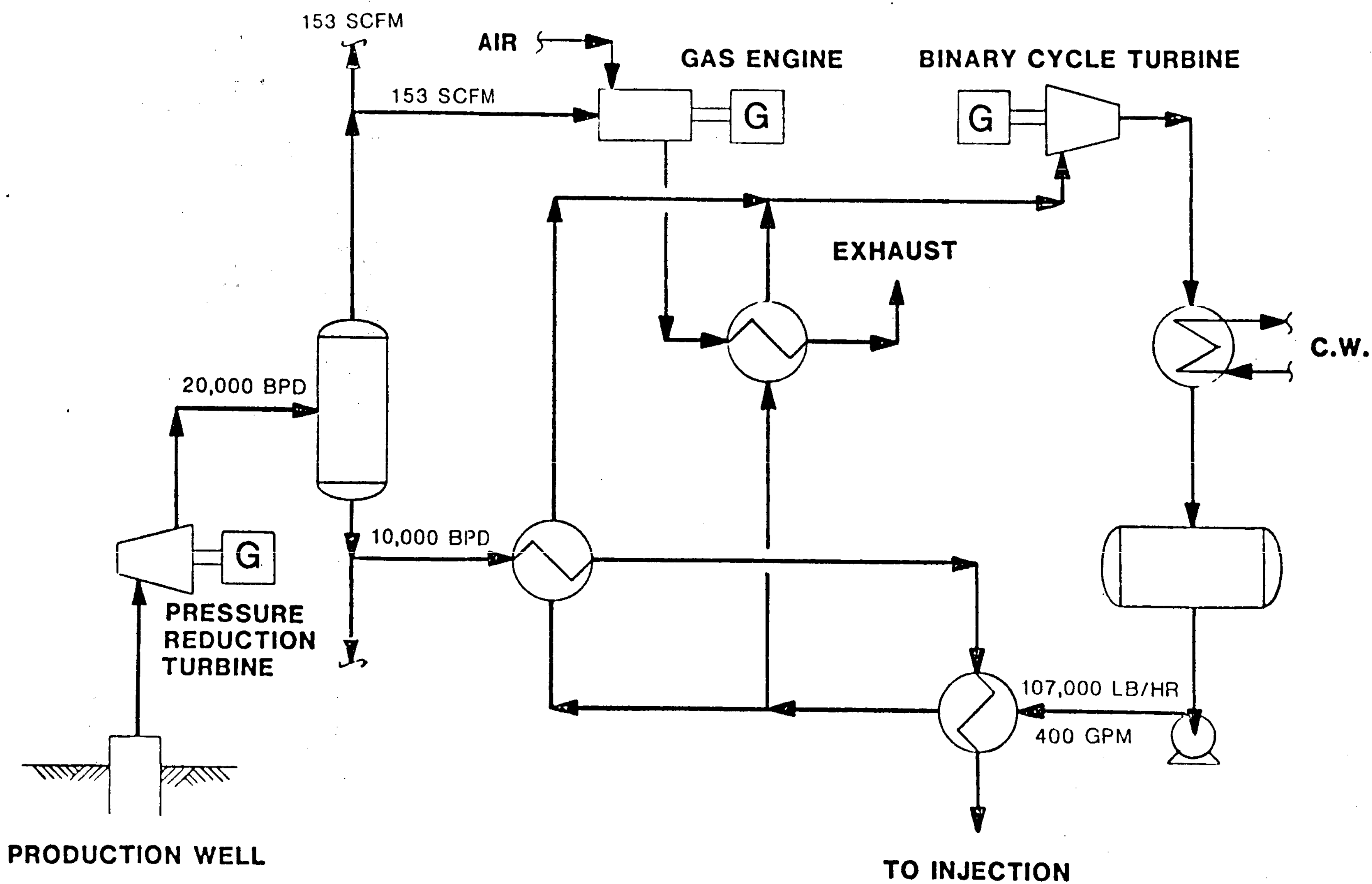
The 1-MWe power system for the experiment has been designed for the Pleasant Bayou geopressured well; the design uses binary cycle equipment made available to EPRI by DOE. This equipment has been removed from its former site at East Mesa in the Imperial Valley of California. Refurbishment is 80 percent complete. Most of the equipment is stored at a subcontractor's facility in the Imperial Valley. Two major subsystems are being refurbished at other sites: the power trailer near Denver and the control trailer near Los Angeles. Two of the heat exchangers have been fabricated as new equipment for this experiment. The third heat exchanger (exhaust gas to boiling isobutane) is being specified for purchase. All the equipment, except for this last heat exchanger, can be shipped to the Pleasant Bayou site in April if the site is ready for receipt of the power system. The last heat exchanger can be shipped about six weeks later.

PLANS

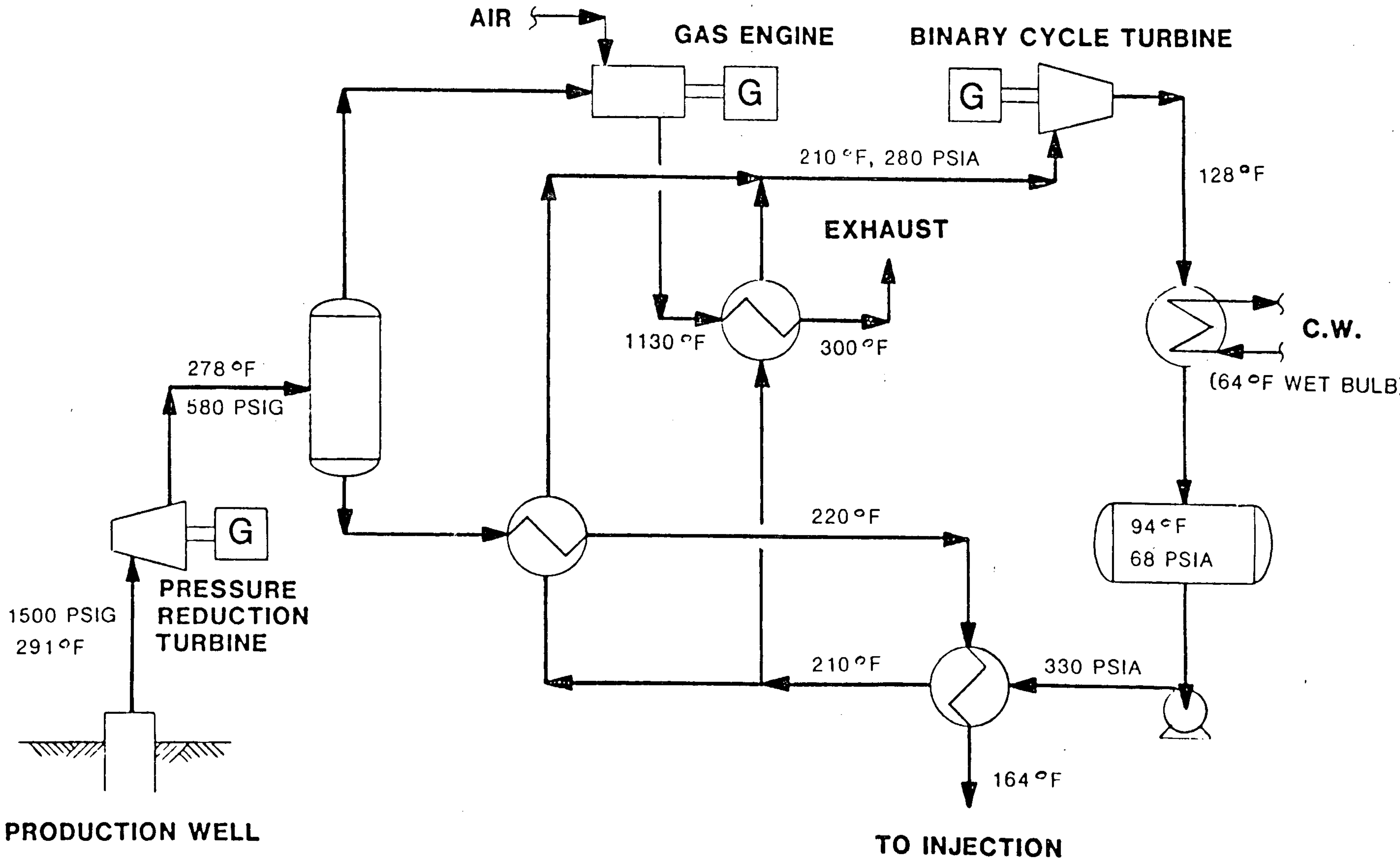
EPRI plans to deliver the equipment to the Pleasant Bayou site at the time most suitable given the DOE schedule for completion of the work to prepare the wells and the site. EPRI has made arrangements with WKT and Houston Lighting and Power for their participation in the project as supplier of the gas engine and purchaser of electricity, respectively. EPRI is preparing a Test Plan to set forth details regarding the conduct of the experiment. EPRI plans to monitor the installation and testing of the hybrid power system and to document the results in a final report.

HYBRID CYCLE FLOW DIAGRAM

KEY FLOWS SHOWN



HYBRID CYCLE FLOW DIAGRAM
KEY OPERATING CONDITIONS SHOWN



I. APPENDIX 9

PLEASANT BAYOU GEOLOGY
COMPLETE WRITINGS INCLUDING CROSS SECTIONS

M. LIGHT/N. TYLER - BEG

PLEASANT BAYOU GEOLOGY: A REVIEW

Malcolm Light and Noel Tyler

Bureau of Economic Geology, The University of Texas at Austin

The Pleasant Bayou geopressured-geothermal prospect is situated south of Houston and west of Galveston Bay in Brazoria County, Texas (fig. 1). A summary of the formation, reservoir data, testing, and fluid analyses are given in table 1.

The Oligocene Frio Formation forms one of the principal progradational clastic wedges in the Tertiary Gulf Coast Basin in Texas. It thickens basinward from a few hundred feet of outcropping fluvial Catahoula Formation to 15,000 ft (4,600 m) of deltaic, barrier-strandplain, shelf, and slope deposits. Two deltaic depocenters are separated by a barrier-strandplain system (fig. 2). The Pleasant Bayou geopressured-geothermal test well lies in the Houston Delta System in eastern Brazoria County (fig. 3).

Thick, highly geopressured sandstones occur in the lower Frio Formation below the T5 correlation marker in the Anomalina bilateralis zone. The geostatic ratios (pore fluid pressure/lithostatic pressure) are 0.7 or greater below T5 in the lower Frio sandstones and shales. In contrast, sandstones in the T2 to T5 succession (upper Frio Formation) show less geopressure than adjacent shales and appear to have acted as conduits through which some of the fluids bled off. The upper Frio also shows maturity and geothermal anomalies that resulted from heating by upward-migrating basinal brines.

The Pleasant Bayou test well was drilled in a salt-withdrawal basin piercement salt dome to the west (fig. 4). The geopressured reservoir lies between two large syndepositional normal faults that displace and isolate lower Frio strata (fig. 4).

An west-east cross section of the lower Frio Formation in the Pleasant Bayou area (fig. 5) shows seven major sandstone-shale depositional sequences (A through G) of variable log character that occur in the lower Frio (below the T5 marker horizon).

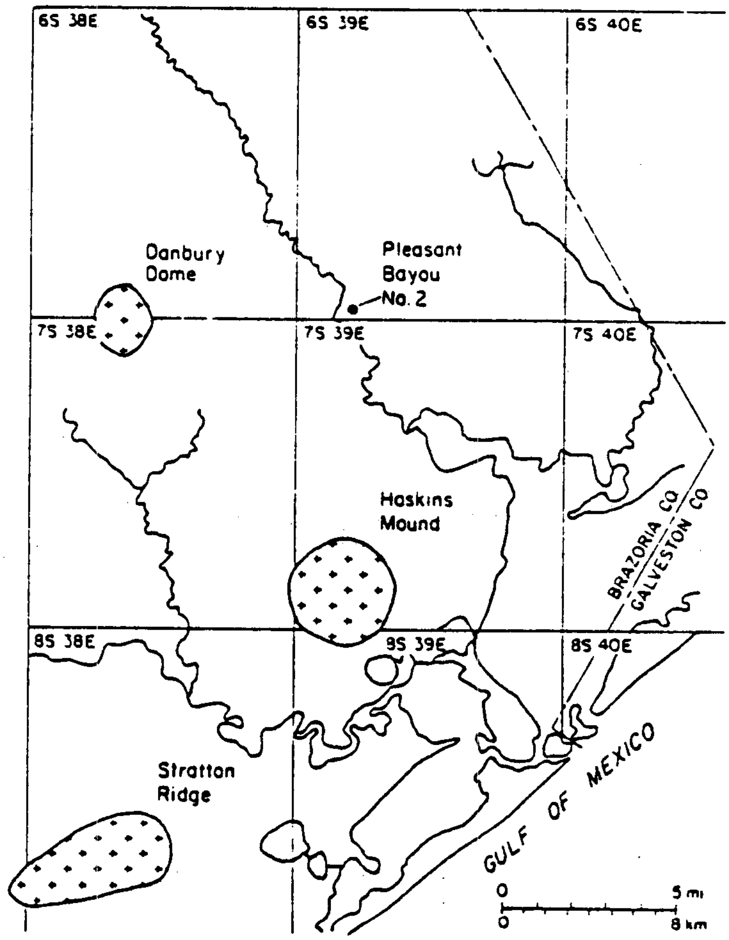


Fig. 1 Location of the General Crude Oil- Department of Energy Pleasant Bayou No. 2 geopressured geothermal design well.

From Morton, 1981

Table 1 Parameters for Pleasant Bayou No. 2

TOTAL DEPTH	16,500'
FORMATION	Frio
Perf. Interval	14,644' to 14,704'
Porosity	19%
RESERVOIR DATA	
Initial Pressure	11,050 psi
Temperature	301°F
Permeability	200 md
No. Barriers	Partial 3,700' Fault ≈ 3 mi
Radial Expl. Dist.	16,525'
Expl. Water Vol.	1.6×10^9 bbls
Est. Area	25 mi^2
TESTING	
Duration	45 days
Flow: Max.	22,752 BPD
Avg.	13,106 BPD
Surface Temp.	255°F
Sand Production	No
FLUID ANALYSES	
TDS	131,320 mg/l
Methane	85.5%
CO_2	10.5%
Gas/Water	29 SCF/bbl

From Morton, 1981

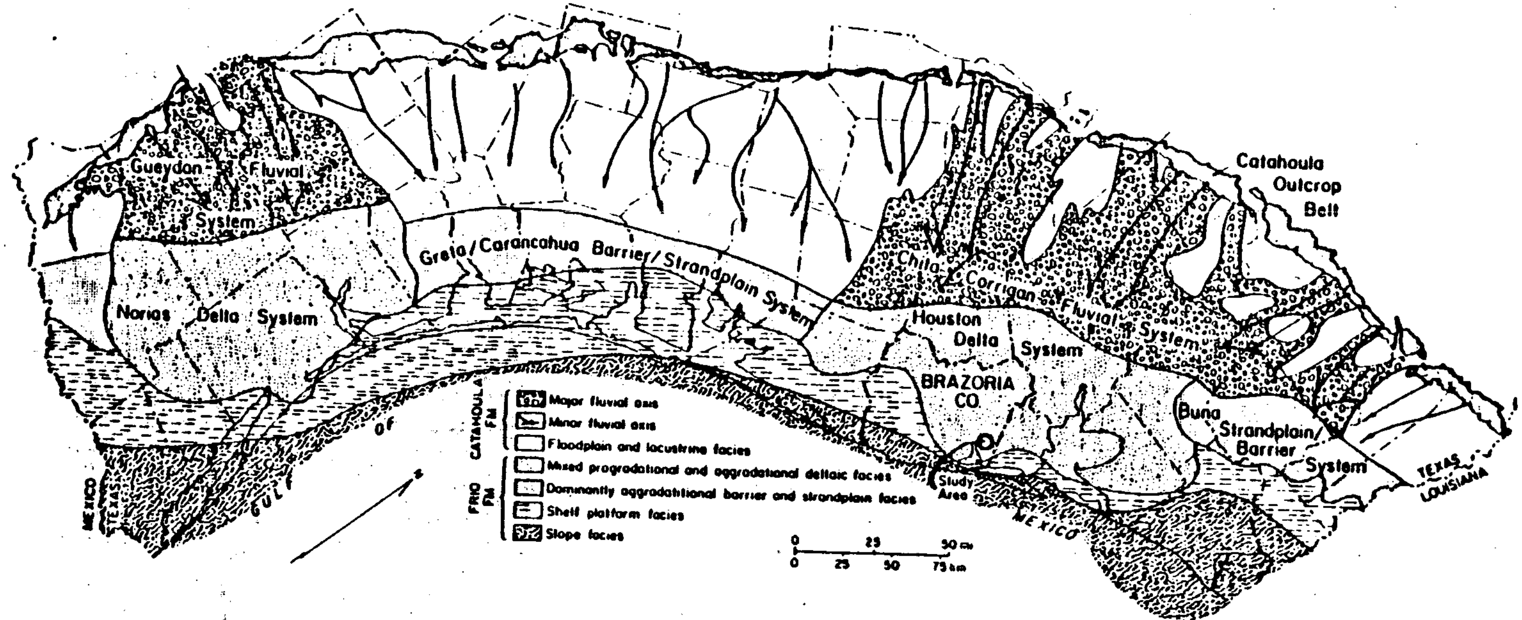


Figure 2 Stratigraphic setting of the lower Frio Formation (modified from Galloway *et al.*, 1982). The present study area is located in the Houston Delta System.

From Tyler and Han, 1982

FRIO DEPOSITIONAL SYSTEMS

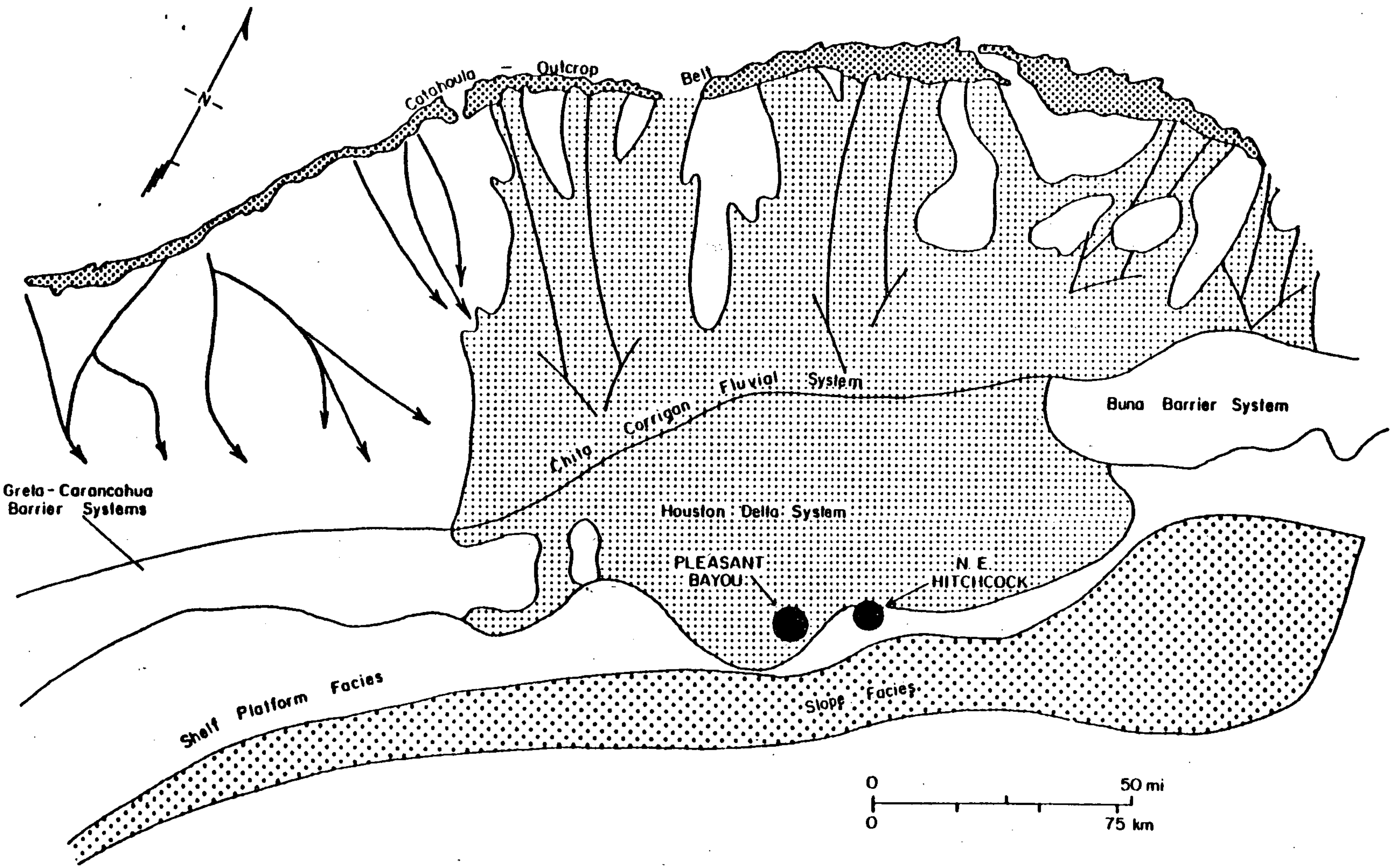


Figure 3. **Regional depositional setting of the Hitchcock N. E. field. (Modified from Galloway, Hobday, and Magara, 1982.)**

From Light, Ewing and D'Attilio, 1985.

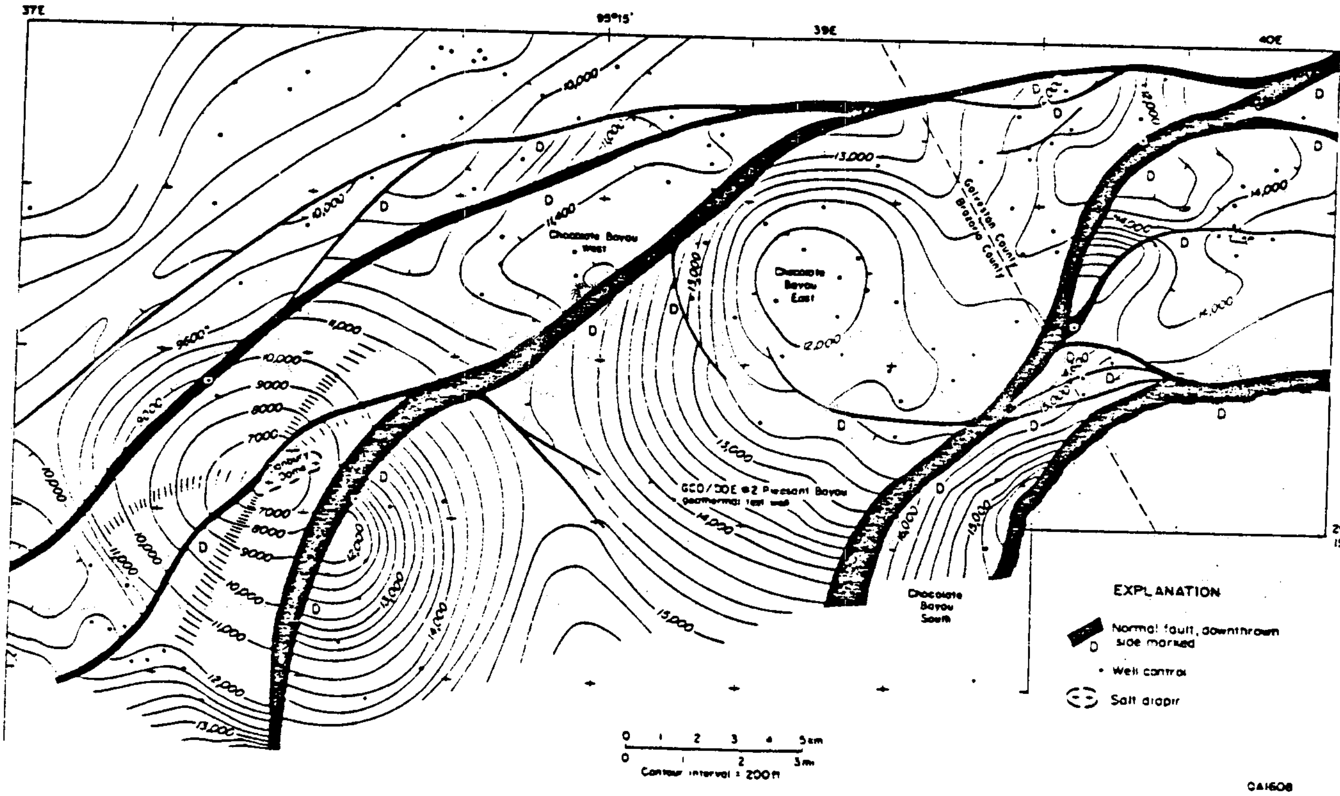


Figure 4. Structure map on the T5 marker, Chocolate Bayou - Danbury Dome area.

From Ewing and others, 1984.

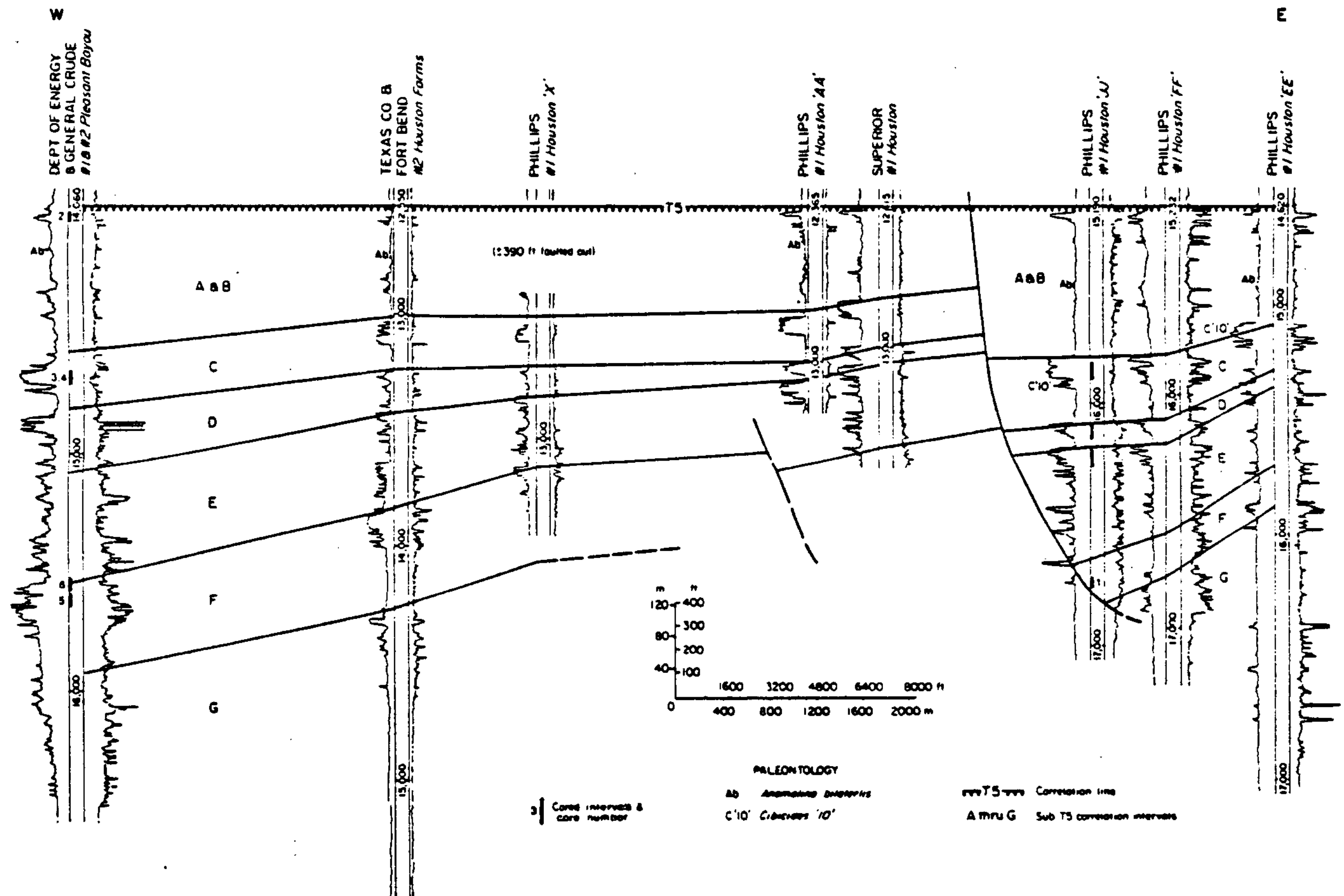


Figure 5. Stratigraphic cross section through the lower Frio Formation illustrating location of cores, thickening of the sub-T5 interval into the Danbury salt withdrawal subbasin (towards the west) and the displacement and expansion effects of syngenetic growth faulting.

From Tyler and Han, 1982

In addition, the *Anomalina bilateralis* zone, cored intervals, and the southern bounding fault of the fault block are shown (fig. 5). Figure 6 is a strike section that extends from the Chocolate Bayou Dome to the northeast through the Pleasant Bayou test well to the Skrabanek No. 1 well south of Danbury Dome. Total sandstone thickness in the upper Frio (T5 to T6 interval) varies from more than 1,200 ft (366 m) in the Danbury Dome area to less than 200 ft (61 m) northeast of the Chocolate Bayou field (fig. 6).

The *Anomalina bilateralis* zone in Galveston and Brazoria Counties is characterized by relatively high sandstone content compared with overlying successions. The Pleasant Bayou test well area lies downdip of the main T5 to T6 depocenter, a narrow (10 to 30 mi [16 to 48 km] wide) belt that contains more than 40 percent sandstone (fig. 7). The geometry from net sandstone mapping is dominantly lobate with local dip-elongate elements (fig. 7). The main axis of sediment transport across the fault system was near Danbury Dome, and a subsidiary axis occurred over the Chocolate Bayou field (fig. 7).

Regional subsidence was moderate during deposition of the lower Frio, allowing progradation of a high-constructive delta system (fig. 8). During later stages (middle and upper Frio) subsidence exceeded sedimentation during a period of coastal onlap and shale became abundant.

Spontaneous-potential logs indicate rapidly upward coarsening to blocky sandstone that is extensive in both dip and strike directions (fig. 9). The well-defined lobate to elongate net sandstone patterns and log character indicate that the sand-shale sequences of the lower Frio were deposited by a high-constructive lobate delta (fig. 7). This is substantiated by geological and micropaleontological analyses of cores and cuttings from the test well.

The Andrau "C" distributary-mouth-bar complex that composes the productive sandstones in the test interval consists of crossbedded, poorly to moderately sorted coarse-grained sandstone that was characterized by high rates of sedimentation (fig. 10). Winnowed and reworked sandstones in the lower part of the sequence give way to sandstones of variable texture and maturity at the bar crest. Very coarse distributary channel sandstones cap the succession and have eroded into the bar crest

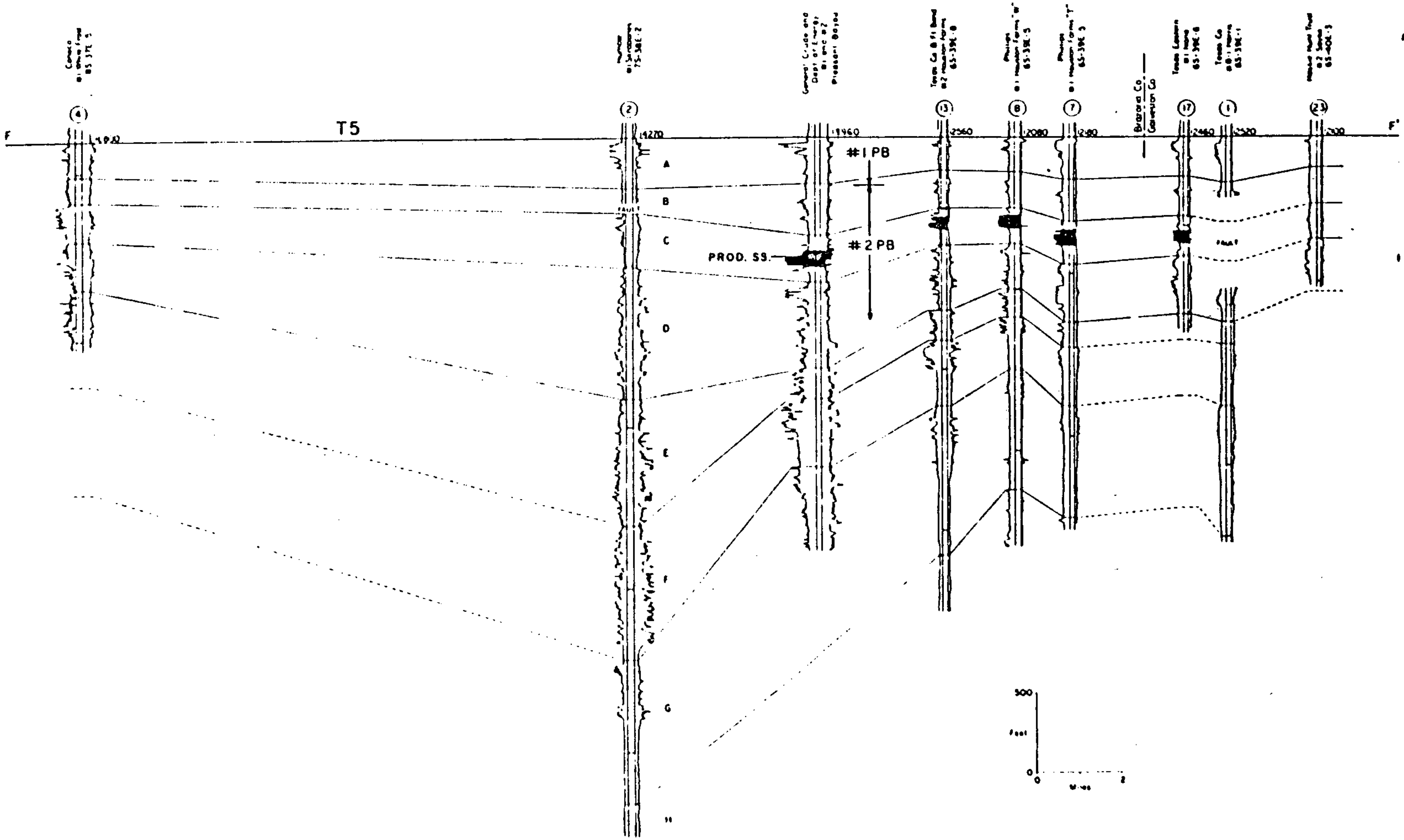


Figure 6.

STRATIGRAPHIC SECTION FF'. MODIFIED FROM BEBOUT, LOUCKS, AND GREGORY (1978).

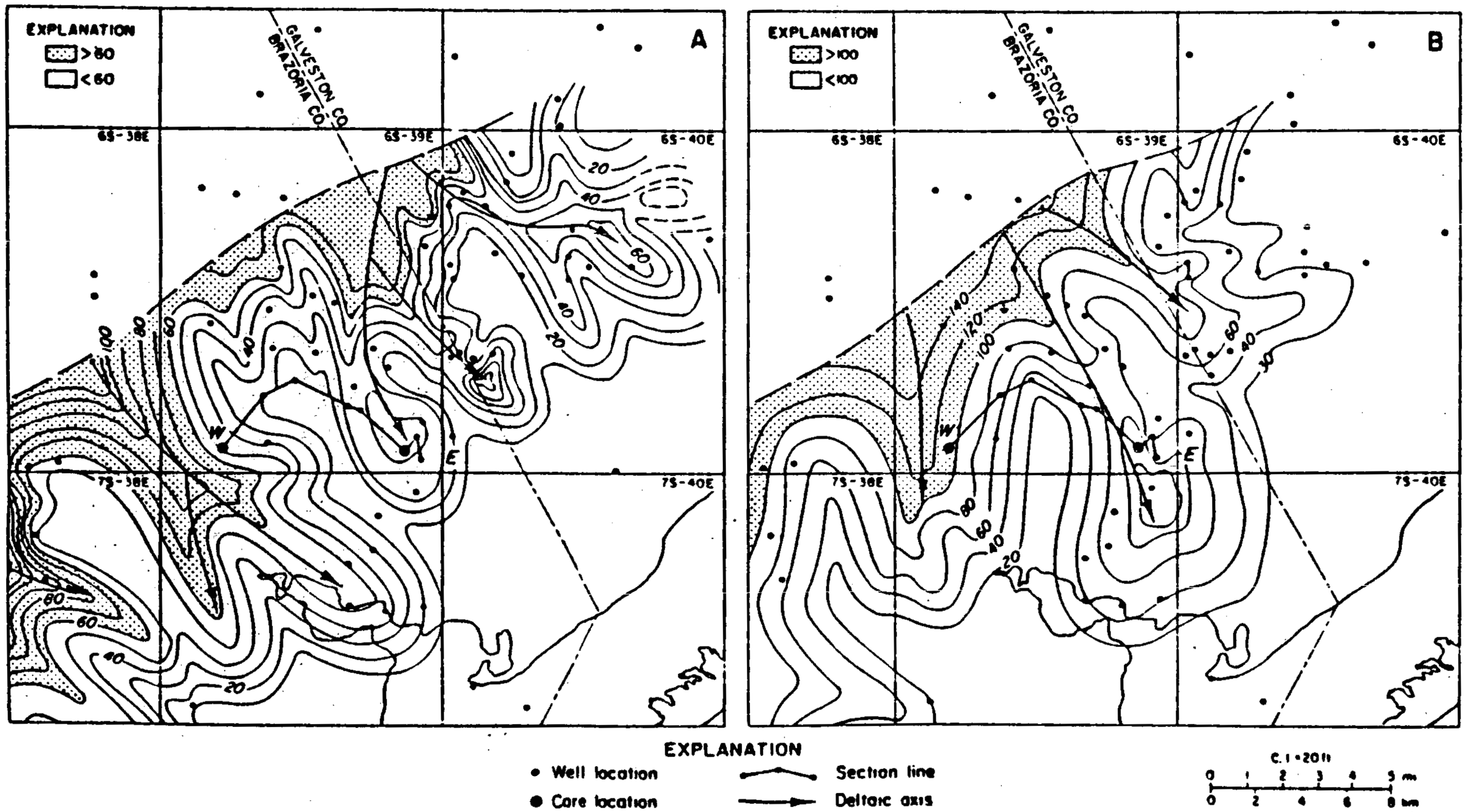


Figure 7.Net sand map of the sub-T5 A correlation inverval (A), and C correlation interval (B), modified after Bebout *et al.* (1979). Sandstones of both intervals exhibit elongate to lobate patterns and axes of maximum sandstone development are divergent. Contours in feet.

From Tyler and Han, 1982.

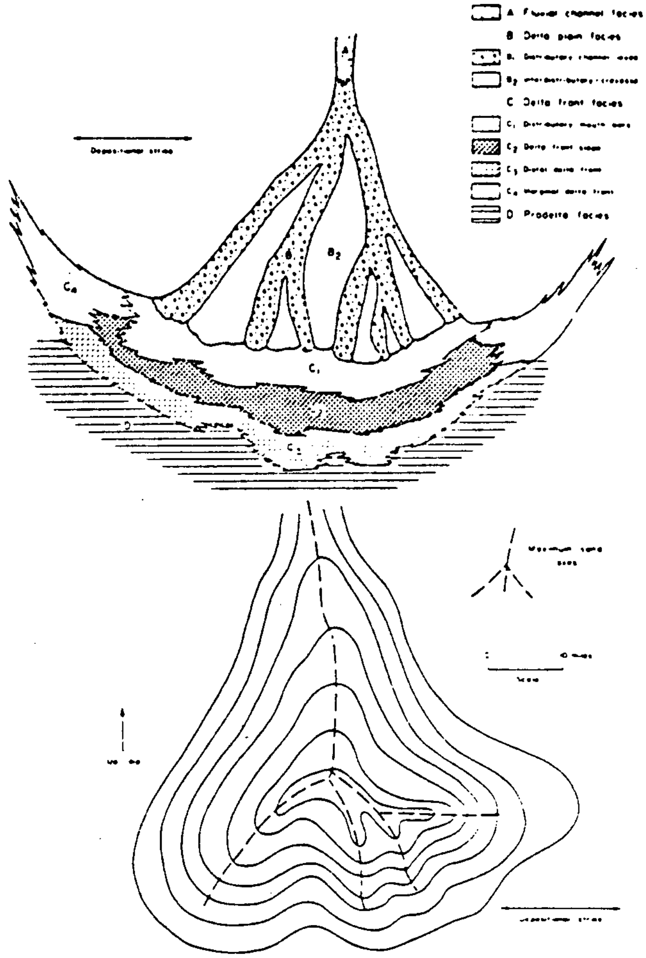


Figure 8.

Principal depositional environments and sand patterns, high-constructive lobate delta systems, Gulf Coast Basin (Fisher and others, 1969).

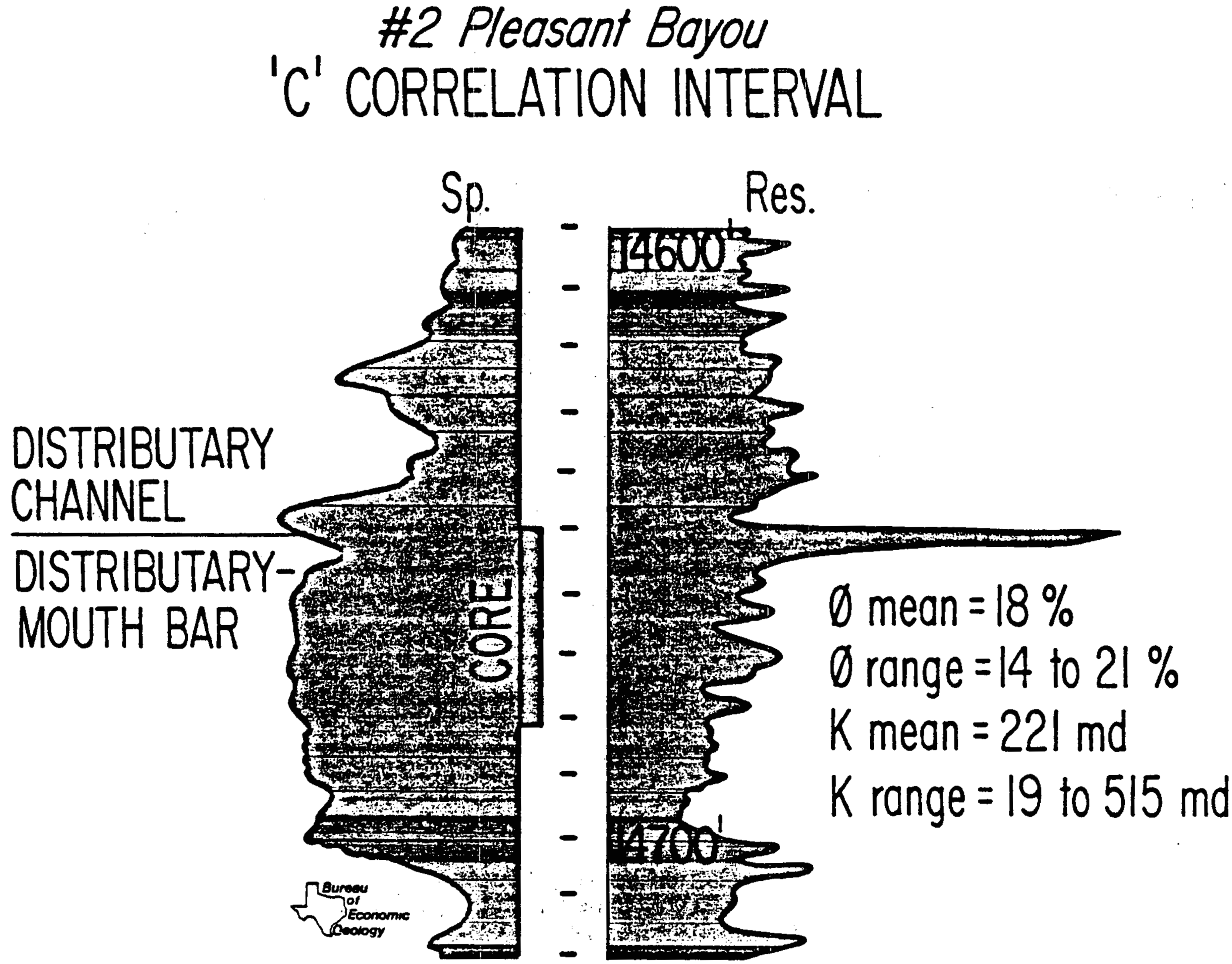


Figure 9. Porosity is dominantly secondary below 10,000 ft (3,050 m) in Pleasant Bayou and within the less thermally mature but highly geopressured distributary mouth-bar sandstones of the lower Frio.

Figure 10 Cross-stratified distributary mouth bar sandstones sub-T5 C correlation interval, Pleasant Bayou wells.

From Tyler and Han, 1982

during continued progradation of the delta system. The curvilinear, laterally continuous distributary-mouth-bar sandstones have a higher production potential than do interstratified sandstones and mudstones of the distal delta front, even though cumulative sandstone thicknesses may be equivalent. Figure 11 is a composite model showing characteristics of several lower Frio sandstones in the Pleasant Bayou area. Continuity of coalesced mouth-bar deposits points to considerable wave modification. Constructive elements of the delta system include storm-induced delta-front slumps and splays, distributary-mouth-bars and channels, crevasse splays, and floodplain deposits (fig. 11).

The diagenetic evolution of the Frio Formation has been intensively studied at the Bureau of Economic Geology and includes cementation, replacement, and leaching (fig. 12). Regional studies of reservoir quality of deep Frio sandstones have shown a progressive increase in reservoir quality from the Lower to the Upper Texas Gulf Coast. The Andrau "C" distributary-mouth-bar sandstone interval contains quartz overgrowths and kaolinite that fills leached pore spaces but has higher porosity and permeability than distributary channel, levee, slump, and splay sandstones (fig. 12).

The general sequence of diagenesis established for Tertiary strata in the Gulf Coast has been combined with burial history data from the Pleasant Bayou test well (figures 13 and 14). The thermal evolution of the lower Frio indicates that quartz overgrowths began to form 25 Ma ago, leaching and secondary porosity 19.5 Ma ago, kaolinite 14 Ma ago, and albitization less than 5 to 7.5 Ma ago (fig. 14).

Morton (1981) has dated the smectite-illite transformation in the Pleasant Bayou well at 23.6 Ma ago (fig. 15). The quartz overgrowths began to form in the sandstones at this time as a result of silica released during the transition of smectite to illite (fig. 15). Albite, which forms at temperatures in excess of 248°F (120°C) is out of equilibrium with present formation waters indicating, that they migrated into the Andrau "C" sandstone after 5 to 7.5 Ma.

The trends shown by salinity (which increases with depth) and chlorine/bromine ratios at the Pleasant Bayou well suggest that the lower Frio is an area of mixing of deep saline basinal fluids with shallower connate waters (fig. 16). Kharaka and others (1979) showed that the chlorine/bromine ratios of the waters in the Andrau "C"

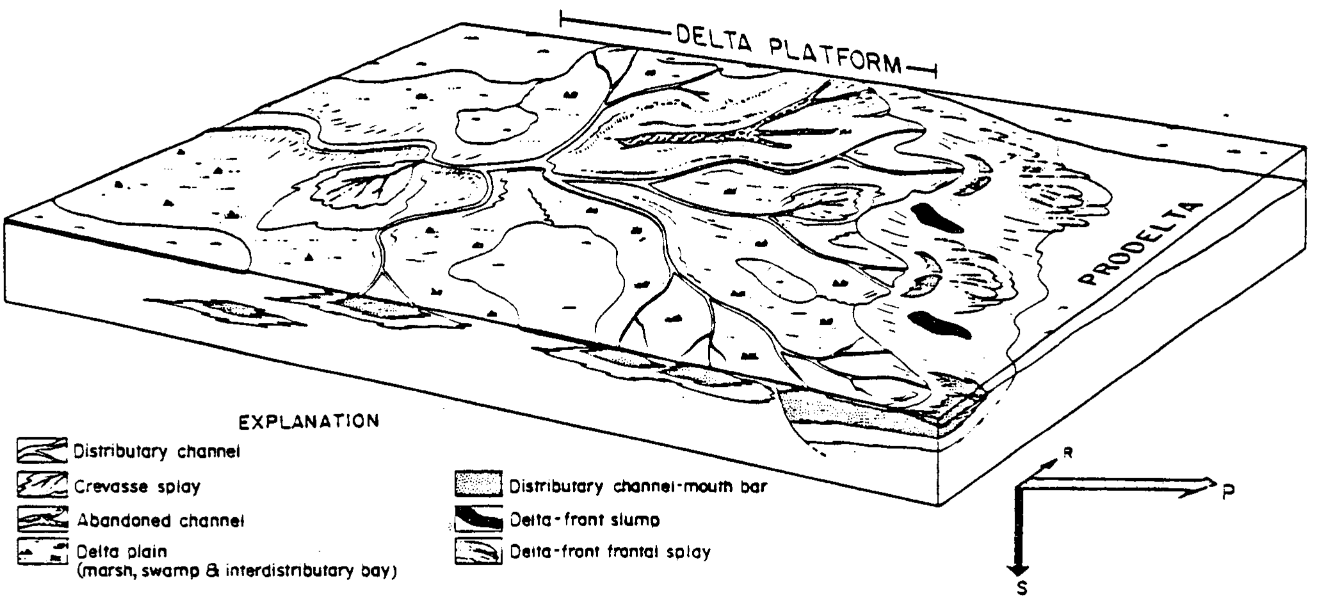


Figure 11 Deposition model of high constructive deltaic deposits of the lower Frio Formation, Brazoria County, Texas.

From Tyler and Han, 1982

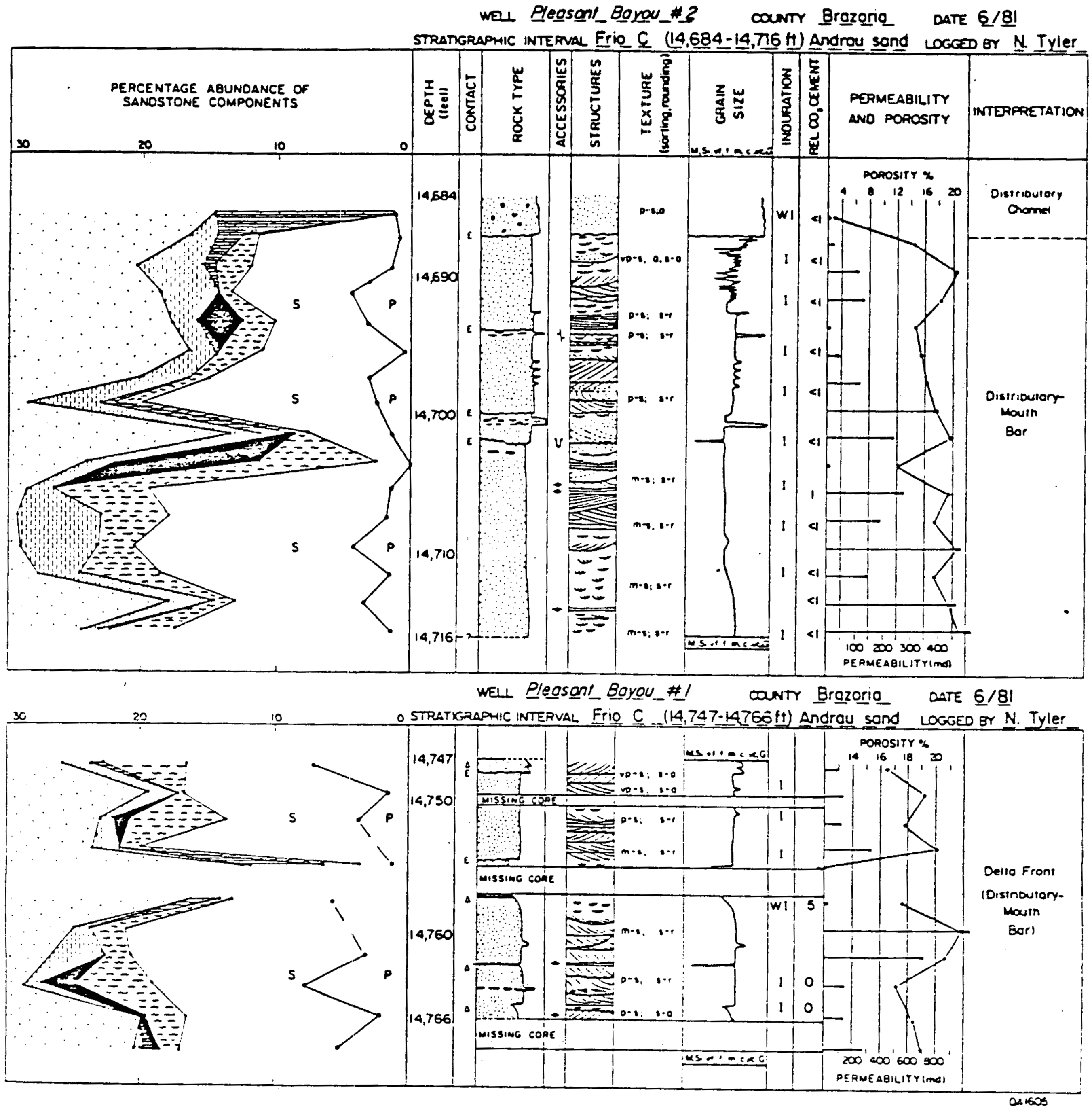


Figure 12. Detailed core description and petrography of distributary-mouth-bar sandstones, Andrau sandstone, Pleasant Bayou No. 1 and No. 2 wells. Modified from Morton and others (1983).

From Ewing and others, 1984

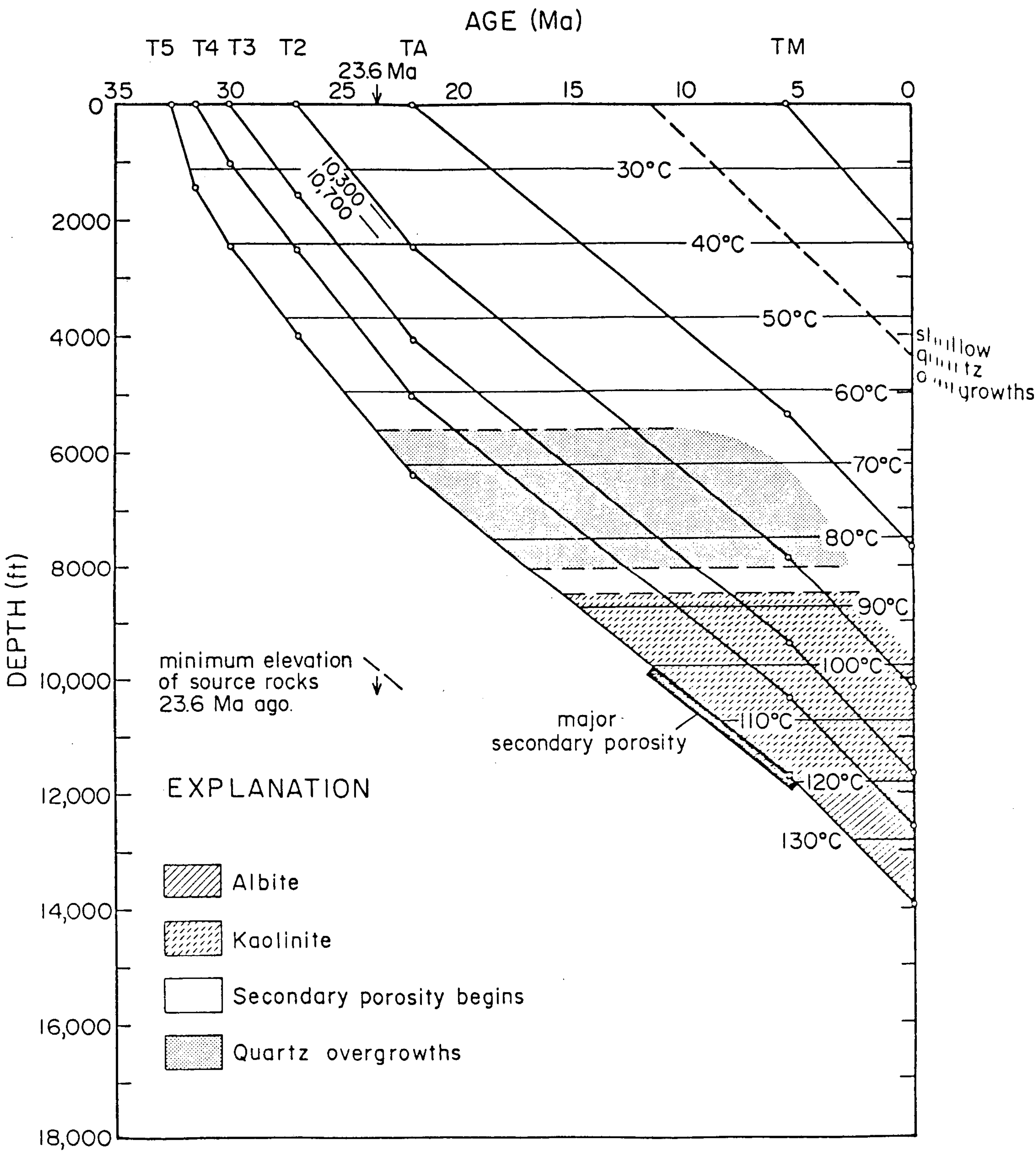


Figure 13. Burial history diagram for the Pleasant Bayou geopressured geothermal test well.

From Light and Ewing, 1985

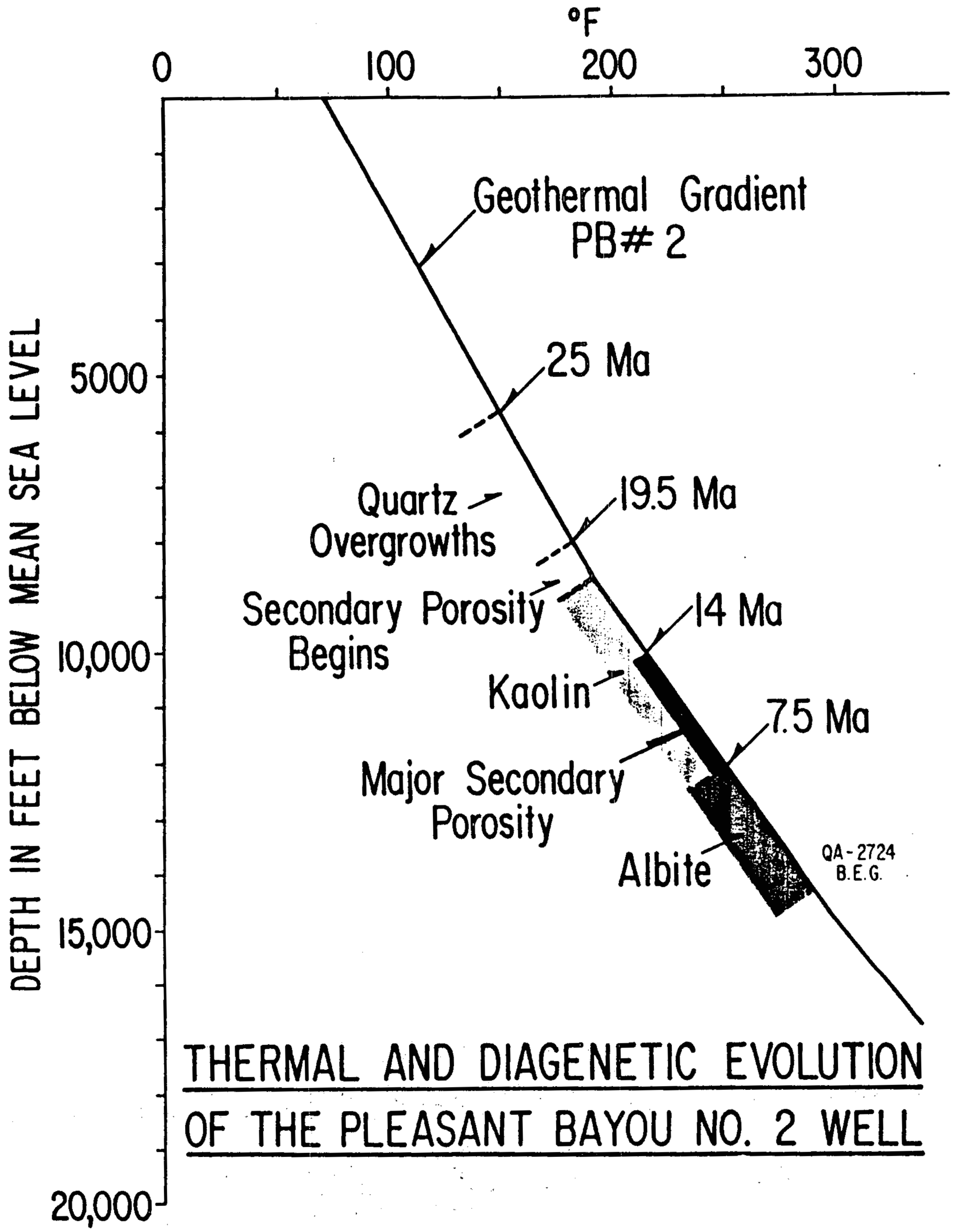


Figure 14. Thermal and porosity evolution at Pleasant Bayou suggests that fluid flow began some 25 Ma ago, whereas the anomaly in the extant geothermal gradient indicates that it is still active in the upper Frio Formation.

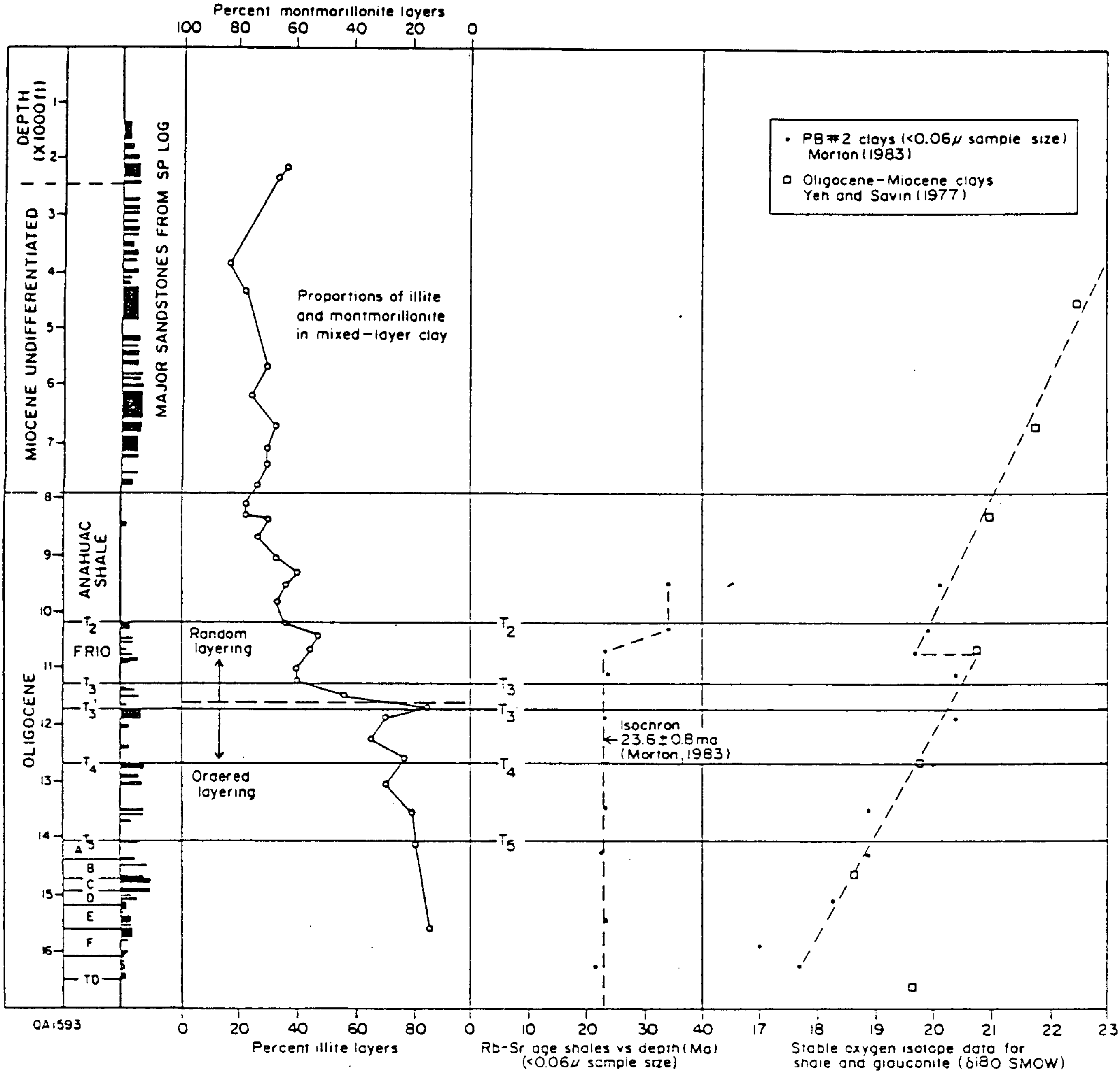


Figure 15. Proportion of illite and smectite in mixed-layer clays vs. depth, Pleasant Bayou No. 1 well (Freed, 1979); apparent Rb-Sr age of clays <0.06μm in diameter vs. depth in the test well (Morton, 1983); and oxygen isotope values for shale and glauconite vs. depth in the test well (Yeh and Savin, 1977; Morton, 1983).

From Ewing and others, 1984

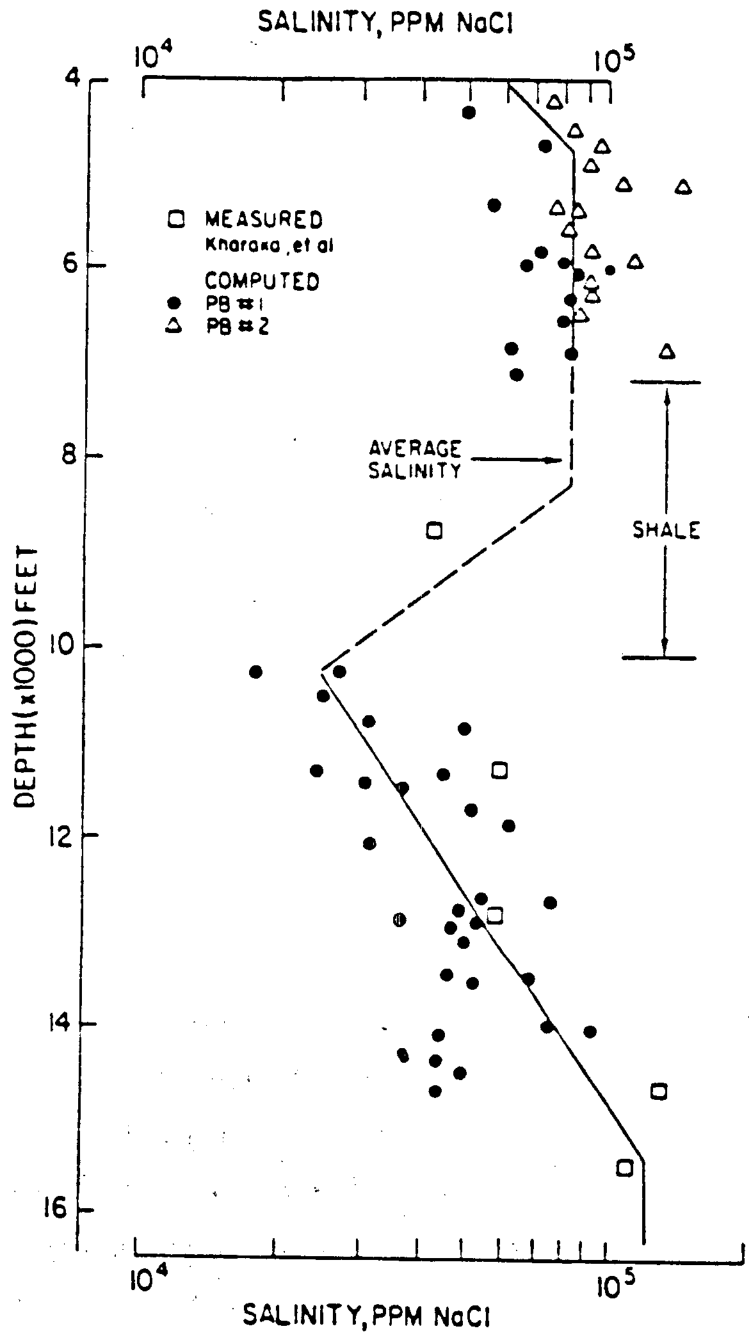


Figure 16.

Salinity profile at the GCO-DOE Pleasant Bayou wells.

From Gregory and Backus, 1979

sandstone indicate that they have a large component derived from salt dissolution. These fluids lie in a central region between pure salt, seawater, and meteoric water (fig. 17). Hoskins Mound and Stratton Ridge (salt structures) lie southeast and south of the Pleasant Bayou - Chocolate Bayou fault block and intersect the main fault system forming the southeast margin of the Chocolate Bayou oil and gas field (fig. 18). Deep dissolution of these domes by migrating hot basinal waters that originated in the upper Vicksburg slope shales and were driven landward by a horizontal pressure gradient could produce the high chlorine/bromine ratios of the Pleasant Bayou brines (fig. 18).

Geothermal gradient and shale and hydrocarbon maturity and composition data indicate that the upper Frio section was flushed by hot basinal waters less than 5 to 7.5 Ma ago (fig. 19). High geopressure has retarded migration in the lower Frio Formation (below the T5 marker horizon)(fig. 19). These deep basinal waters are rich in aromatic hydrocarbons, calcium, and heavy metals (Pb,Zn) released by albitization of feldspars at depth. Permeability in the upper Frio was reduced by precipitation of carbonates (fig. 20). In the lower Frio higher permeabilities were preserved by the high geopressure that retarded the influx of hot, calcium-rich waters (fig. 20).

Data gathered at the Pleasant Bayou well site have been of immense value in deciphering the diagenetic and hydrocarbon migration systems of this part of the Gulf Coast. Geothermal and thermal maturity data (fig. 21) can be used locally and regionally to define (a) the lateral extent, thickness and continuity of highly permeable geopressured formations at depth (fig. 22), (b) the location of individual sandstone bodies that have acted as major conduits for upward migration of very saline brines containing hydrocarbons, heavy metals, and calcium carbonate (fig. 22), (c) the location of sections of growth fault planes that are sealing with respect to saline fluid flow and that have acted as conduits (fig. 22). Areal mapping of migration pathways using borehole pressure and electric-log data may lead to the identification of updip hydrocarbon-bearing traps or heavy-metal deposits (fig. 22).

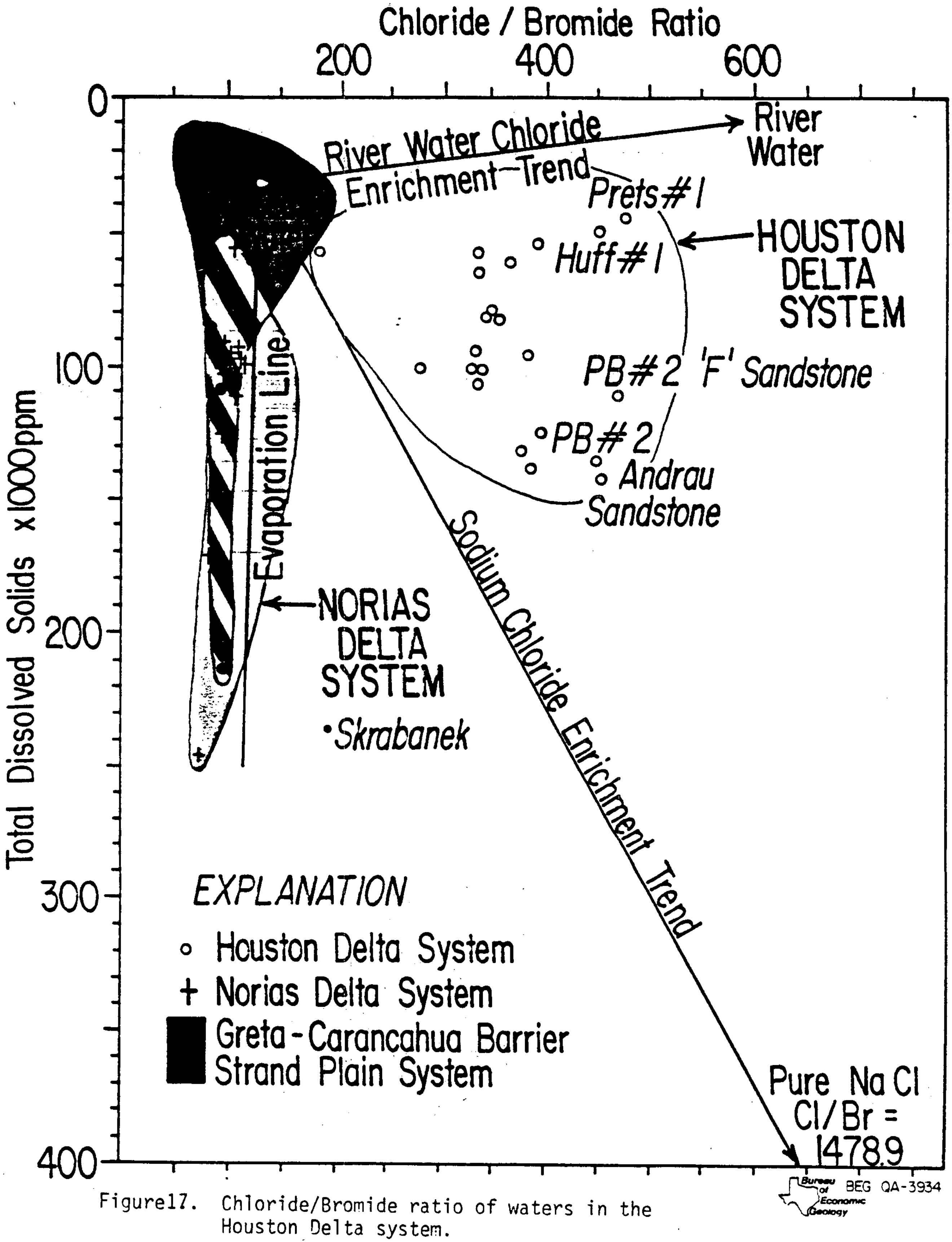


Figure17. Chloride/Bromide ratio of waters in the Houston Delta system.

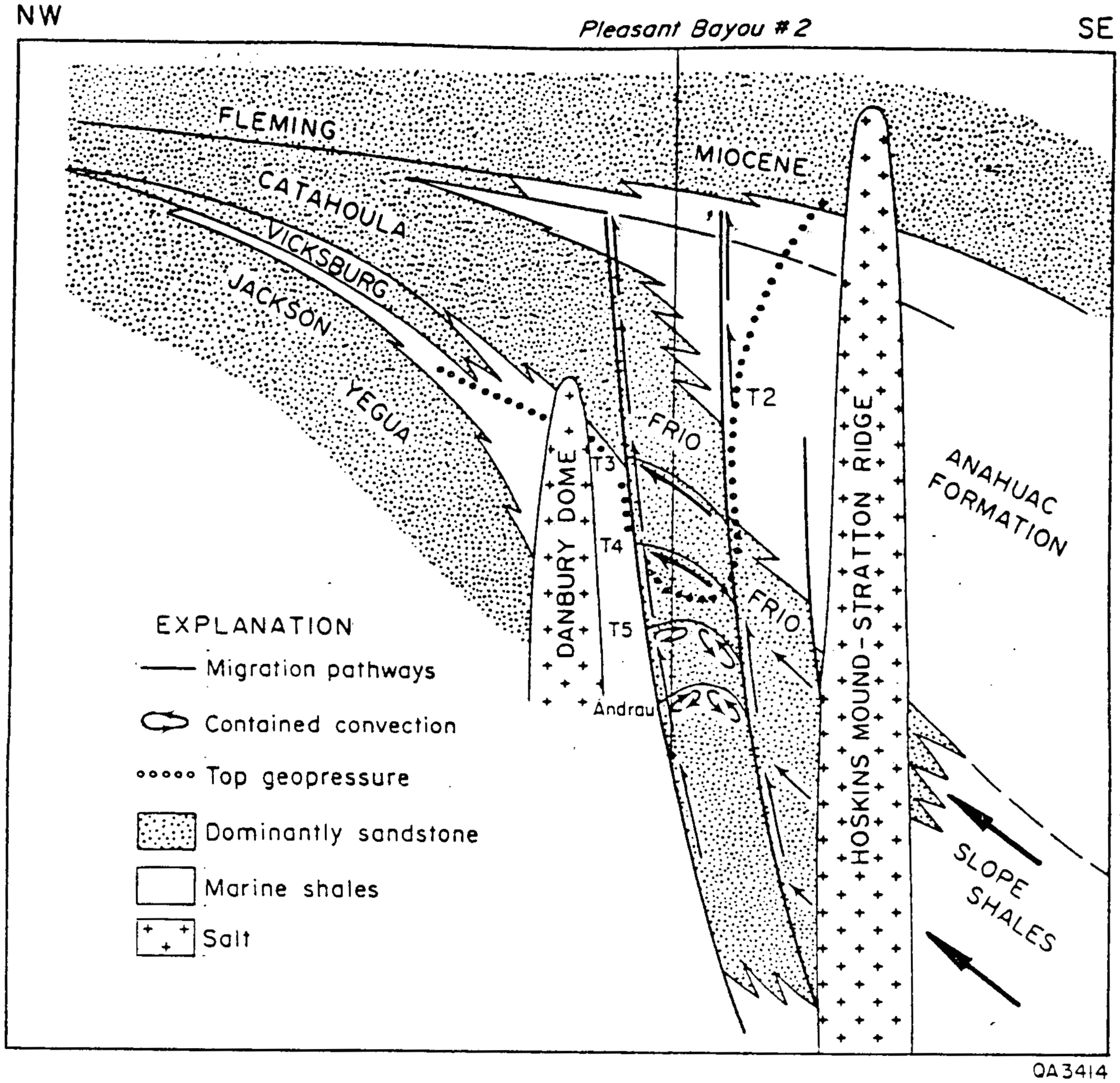


Figure 18 . Stylized stratigraphic dip section across the Texas Gulf Coast showing the relative position of the GCO/DOE Pleasant Bayou geopressured geothermal test wells (modified from Galloway, Hobday, and Magara, 1982).

From Light and Ewing, 1985

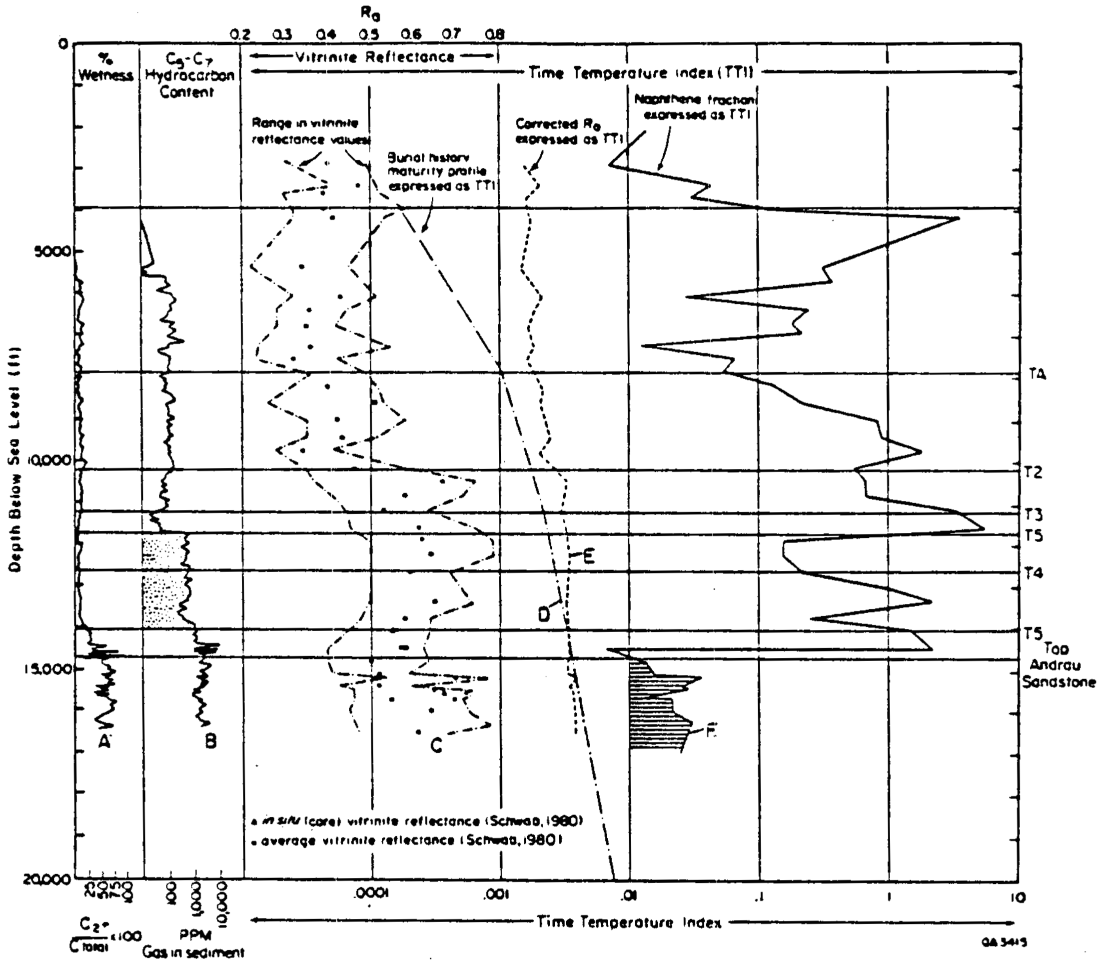


Fig.19 . Naphthene fraction expressed as time-temperature integrals (TTI) vs. depth for the Pleasant Bayou No. 1 well compared with the burial history maturity profile and the corrected vitrinite reflectance both expressed as time-temperature integrals (TTI). The uncorrected vitrinite reflectance, percent wetness, and C_5-C_7 hydrocarbon content in 1 million volumes of sediment vs. depth is shown for comparison. Stipple pattern represents a zone containing anomalous concentrations of C_5 to C_7 hydrocarbons; lined pattern indicates zone containing hydrocarbons consistent with depth and thermal gradient.

From Tyler, Light and Ewing, 1985

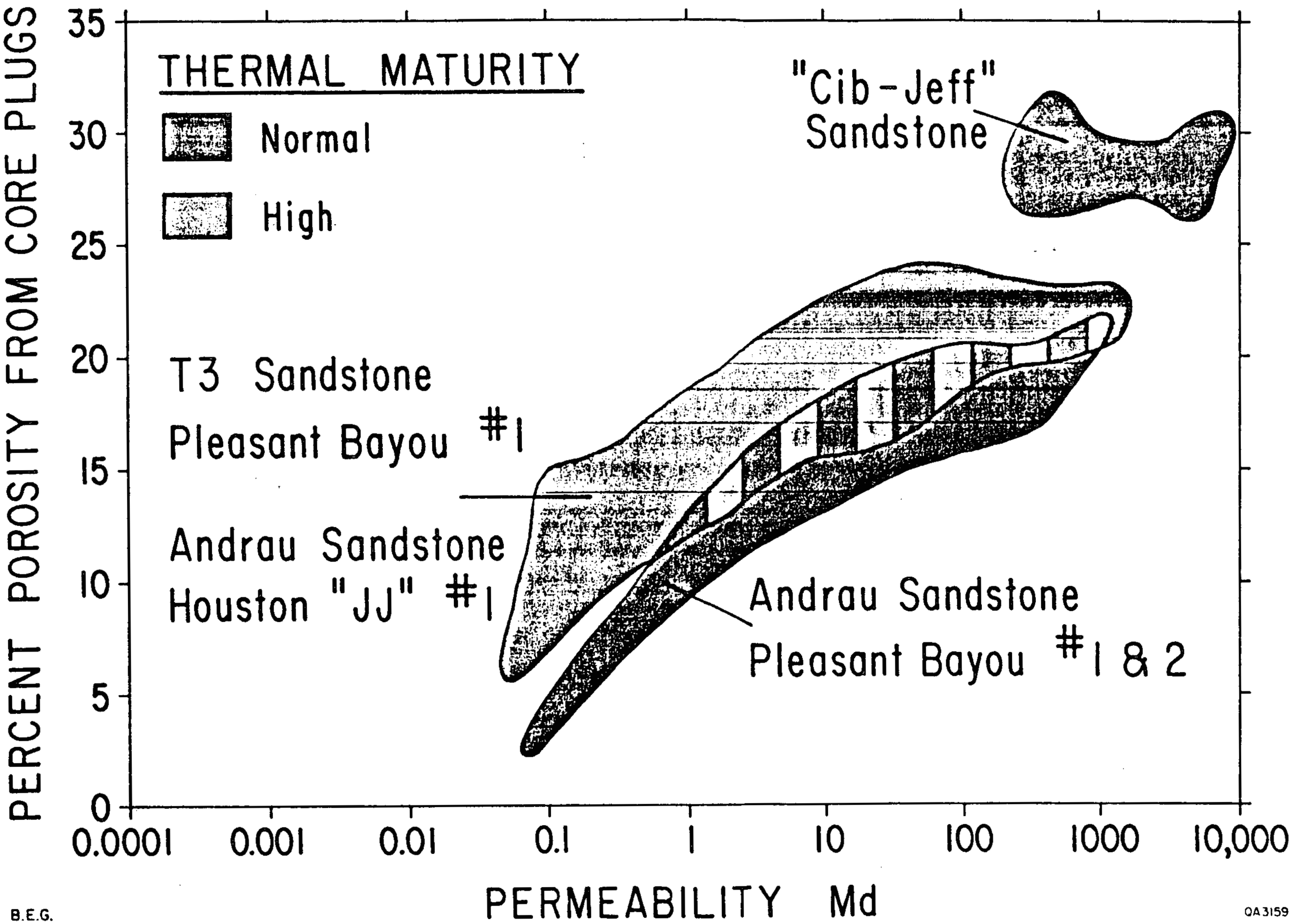


Figure 20. The lower Frio sandstones, which show normal maturity are more permeable by an order of magnitude than the more mature shallower upper Frio sandstones.

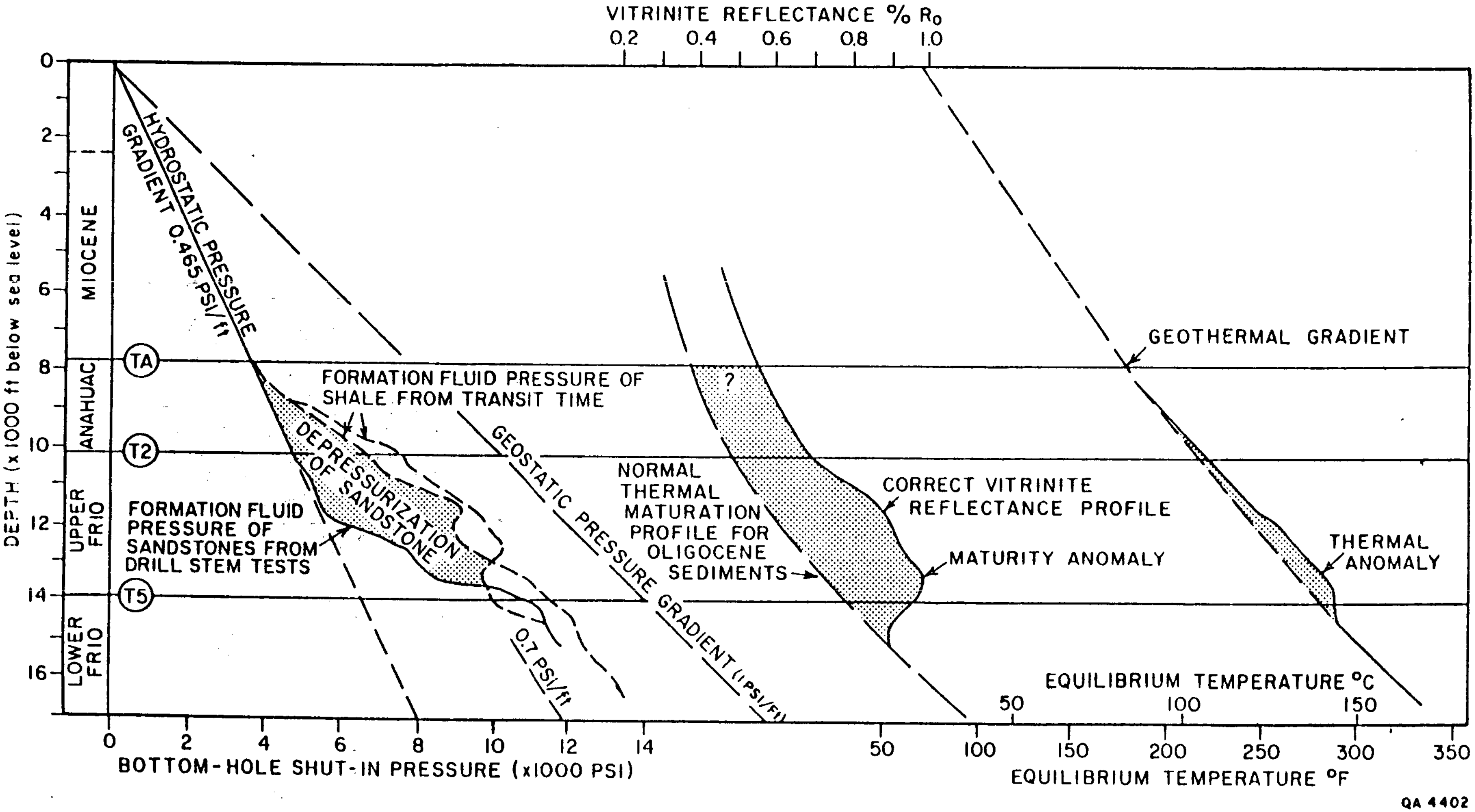


Figure 21. Fluid pressure, geothermal and thermal maturity profiles for the Pleasant Bayou No.2 test well. Modified from Ewing, Tyler and Light, 1983. From Light and Ewing, 1985

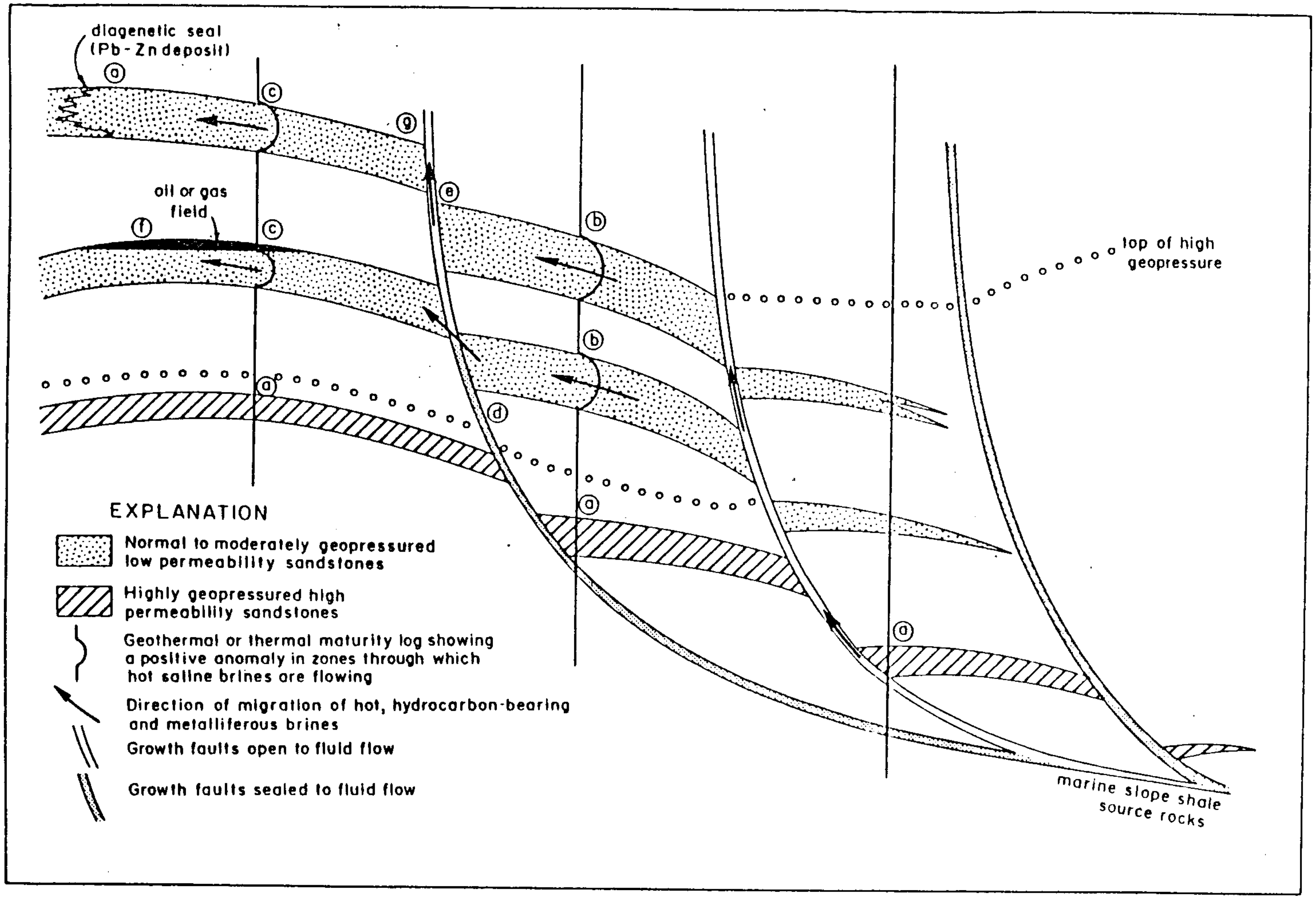


Figure 22. Schematic cross section showing the use of geothermal, paleogeothermal or pressure data to identify the extent of highly permeable highly geopressured sandstones, conduits for hot fluid migration and updip hydrocarbon and metalliferous deposits

From Light and Ewing, 1985

REFERENCES

Bebout, D. G., Loucks, R. G., and Gregory, A. R., 1979, Geological aspects of Pleasant Bayou geopressured geothermal test well, Austin Bayou prospect, Brazoria County, Texas, in Proceedings Fourth Conference on Geopressured Geothermal Energy: The University of Texas at Austin, p. 11-45.

Bebout, D. G., Loucks, R. G., and Gregory, A. R., 1978, Frio sandstone reservoirs in the deep subsurface along the Texas Gulf Coast--their potential for production of geopressured geothermal energy: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 91, 92 p.

Ewing, T. E., Light, M. P. R., and Tyler, N., 1984, Section IV. Integrated geologic study of the Pleasant Bayou - Chocolate Bayou area, Brazoria County, Texas--first report in Ewing, T. E., Tyler, N., Morton, R. A., and Light, M. P. R., Consolidation of geologic studies of geopressured geothermal resources of Texas: The University of Texas at Austin, Bureau of Economic Geology, report prepared for the U.S. Department of Energy under contract no. DE-AC08-79ET27111, p. 90-142.

Fisher, W. L., Brown, L. F., Scott, A. J., and McGowen, J. H., 1969, Delta systems in the exploration for oil and gas: The University of Texas at Austin, Bureau of Economic Geology Special Publication, 102p.

Freed, R. L., 1979, Shale mineralogy of the No. 1 Pleasant Bayou geothermal test well: a progress report, in Proceedings, Fourth Conference on Geopressured Geothermal Energy: The University of Texas at Austin, p. 153-167.

Galloway, W. E., Hobday, D. K., and Magara, K., 1982, Frio Formation of the Texas Gulf Coast Basin--depositional systems, structural framework, and hydrocarbon origin, migration, distribution and exploration potential: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 122, 78 p.

Gregory, A. R., and Backus, M. M., 1979, Geopressured formation parameters, geothermal well, Brazoria County, Texas, in Proceedings, Fourth Conference on Geopressured Geothermal Energy: The University of Texas at Austin, p. 235-311.

Kharaka, Y. K., Lies, M. S., Wright, V. A., and Carothers, W. W., 1979, Geochemistry of formation waters from the Pleasant Bayou No. 2 well and adjacent areas in coastal Texas, in Proceedings, Fourth Conference on Geopressured Geothermal Energy: The University of Texas at Austin, p. 11-45.

Light, M. P. R., and Ewing, T. E., 1985, Consolidation of geologic studies of geopressured geothermal reources in Texas: The University of Texas at Austin, Bureau of Economic Geology, report prepared for the U.S. Department of Energy under Contract no. DOE/ET/27111-12, 90 p.

Light, M. P. R., Ewing, T. E., and D'Attilio, W., 1985, Coordination of geological and engineering research in support of Gulf Coast co-production program: The University of Texas at Austin, Bureau of Economic Geology, report prepared for the Gas Research Institute under Contract no. 5084-212-0924, 211 p.

Morton, J. P., 1983, Age of clay diagenesis in the Oligocene Frio Formation, Texas Gulf Coast: The University of Texas at Austin, Ph.D. dissertation, 33 p.

Morton, R. A., 1981, Pleasant Bayou #2--a review of rationale, ongoing research and preliminary test results, in Proceedings, Fifth Conference on Geopressured Geothermal Energy: The University of Texas at Austin, p. 55-57.

Morton, R. A., Han, J. H., and Posey, J. S., 1983, Variations in chemical compositions of Tertiary formation waters, Texas Gulf Coast, in Morton, R. A., Ewing, T. E., Kaiser, W. R., and Finley, R. J., Consolidation of geologic studies of geopressured geothermal resources in Texas: The University of Texas at Austin, Bureau of Economic Geology, report prepared for the U.S. Department of Energy under contract no. DE-AC08-79ET27111.

Schwab, K. W., 1980, Visual kerogen and vitrinite reflectance analyses of the Pleasant Bayou No. 1 well, Brazoria County, Texas, in Proceedings, Fourth Conference on Geopressured Geothermal Energy: The University of Texas at Austin, p. 85-131.

Tyler, N., and Han, J. H., 1982, Elements of high-constructive deltaic sedimentation, Lower Frio Formation, Brazoria County, Texas: Gulf Coast Association of Geological Societies Transactions, v. 32, p. 527-540.

Tyler, N., Light, M. P. R., and Ewing, T. E., 1985, Saline fluid flow and hydrocarbon migration and maturation as related to geopressure, Frio Formation, Brazoria County, Texas, in Dorfman, M. H., and Morton, R. A., eds., Geopressured-Geothermal Energy: New York, Pergamon, p. 83-92.

Yeh, H. W., and Savin, S. M., 1977, The mechanism of burial metamorphism of argillaceous sediments: 3. Oxygen isotopic evidence: Geological Society of America Bulletin, v. 88, no. 9, p.1321-1330.

J. APPENDIX 10

SURFACE WATER QUALITY
WORK DONE AT PLEASANT BAYOU AND GLADYS McCALL
SHORT SUMMARY

F.M.A. SALEH/W.M. KOCHER - SLU

ABSTRACT

Surface and Grounwater Quality

At the DOE Geothermal-Geopressured Test Sites

In Texas and Louisiana

By
F.M.A. Saleh*

and

W.M. Kocher**

Test sites at both Rockefeller Refuge, LA and Brazoria, TX were monitored for surface and groundwater quality. Before each trip, the number of samples and sampling locations were determined based on well activities, site meteorology and special project goals. At the Rockefeller Refuge site eleven surface water locations, two on-site test wells, two private wells and two city water wells away from the site were sampled. At the Brazoria site, three test wells and four surface water locations were sampled.

Water samples were analyzed for the following parameters: sodium (Na), potassium (K), Magnesium (Mg), Calcium (Ca), Chloride (Cl), Sulfate (SO4), Nitrate (NH3), Manganese (Mn), Cadmium (Cd), Barium (Ba), Lead (Pb), Arsenic (As), Mercury (Hg), Boron (B), Strontium (Sr), Bicarbonate (HCO3), Total Dissolved Solids and Total Organic Carbon. Field measurements included pH, Specific Conductance, Turbidity, Temperature, Dissolved Oxygen and Water Level.

* F.M.A. Saleh, Associate Professor, Civil and Environmental Engineering Department, Southern University, Baton Rouge, Louisiana, 70813.
** W.M. Kocher, Assistant Professor, Civil and Environmental Engineering Department, Southern University, Baton Rouge, Louisiana, 70813.

INTRODUCTION

ASSESS INPACT ON WATER QUALITY

- DIRECT MEASUREMENT
  - SAMPLING / FIELD MEASUREMENTS
  - SAMPLE PRESERVATION / TRANSPORT
  - LABORATORY MEASUREMENTS

RELATE TO ENVIRONMENTAL IMPACT

- INTERPRETATION OF DATA
- SALT WATER INTRUSION (GW)
- TIDAL EFFECTS (SW)

PARAMETERS

GENERAL WATER QUALITY PARAMETERS

pH (REF 2, 4)

TEMPERATURE

DISSOLVED OXYGEN (REF 4)

AMMONIA

DEPTH

SPECIFIC CONDUCTANCE (REF 2)

TURBIDITY

ORGANICS

TOTAL ORGANIC CARBON

REF 1: PRIMARY DRINKING WATER STANDARDS

REF 2: SECONDARY DRINKING WATER STANDARDS

REF 3: NON-HEALTH RELATED WATER QUALITY

REF 4: RAW WATER QUALITY

PARAMETERS

INORGANICS

CATIONS	ANIONS
SODIUM	CHLORIDE (REF 2, 4)
POTASSIUM	SULFATE (REF 2)
CALCIUM (REF 3)	BICARBONATE (REF 3)
MAGNESIUM (REF 3)	NITRATE (REF 1)
STRONTIUM (REF 3)	PHOSPHATE
MANGANESE (REF 2)	
CHROMIUM (REF 1)	
BORON	
BARIUM (REF 1)	
CADMIUM (REF 1)	
LEAD (REF 1)	
ARSENIC (REF 1)	
MERCURY (REF 1)	

SAMPLING TRIPS

SAMPLING METHODS

- SURFACE WATER - BELOW SURFACE
- GROUNDWATER - PUMPING

FIELD ANALYSIS

- TEMPERATURE
- DISSOLVED OXYGEN
- pH
- DEPTH
- CONDUCTIVITY
- TURBIDITY

SAMPLE PRESERVATION / LAB ANALYSIS

Table 1

Description of Sampling Sites

Rockefeller Refuge, LA

Number	Source	Location
1	Well	Water source for crew on DOE site
3	Surface	Dock, NE end of DOE site
4	Surface	Dock, S end of DOE site
5	Surface	Shell Rd. bridge entering DOE site
8	Surface	Shell Rd. bridge, 0.85 miles from DOE site
11	Well	Private residence, 0.1 miles E of Shell Rd.
12	Well	Private residence, 0.8 miles E of Shell Rd. on Rt. 82
13	Well	Rockefeller Refuge, tap near main entrance
14	Surface	Entrance to Private Rd., 0.8 miles E of Shell Rd. on Rt. 82
15	Surface	1.2 miles (opposite house) up Private Rd.
16	Surface	1.9 miles (dock) up Private Rd.
17	Well	Private residence, 1.2 miles E of Shell Rd. on Rt. 82

Description of Sampling Sites

Brazoria, TX

Number	Source	Location
18	Well	Sample well at NW corner of DOE site
19	Well	Sample well at SW corner of DOE site
20	Surface	Bayou sample at SW corner of DOE site
21	Well	Sample well at SE corner of DOE site
22	Surface	Bayou sample at Ways bridge
23	Surface	Bayou sample at dock of Lutes Landing

Table 2 - Results of Ground and Surface Water Samples Analysis at Rockefeller Refuge (December 7-8, 1985)
Page 2

Sample	Cr ppd 0.001 mg/1	Na ppm 0.002 mg/1	K ppm 0.005 mg/1	Mg ppm 0.0005 mg/1	Ca ppm 0.01 mg/1	Mn ppm 0.01 mg/1
	Parameter/Range					
1	1.10	950	4.22	24.15	39.54	0.01
3	1.29	2582	51.47	31.26	69.31	1.06
4	1.81	3115	49.72	29.07	91.06	1.56
5	1.22	3572	48.31	26.14	75.13	0.92
8	1.33	4120	51.93	24.12	76.50	1.26
11	1.16	242	3.35	19.31	93.34	0.03
12	0.62	393	5.19	26.45	16.29	0.01
13	0.73	215	2.13	12.72	8.51	0.00
14	0.81	4275	49.86	25.18	63.25	0.45
15	0.72	4319	50.12	24.92	73.06	0.31
16	1.36	2642	46.26	23.15	42.19	0.34
17	1.05	316	3.42	19.83	15.25	0.02

Sample	Cd ppb 0.002 mg/1	Ba ppm 0.03 mg/1	Pb ppb 0.05 mg/1	As ppb 0.1 mg/1	Hg ppb 0.0001 mg/1	B ppm 0.1 mg/1	Sr ppm 0.01 mg/1
	Parameter/Range						
1	0.0	1.2	0.4	0.6	0.0001	0.0	1.1
3	0.1	0.3	0.0	0.0	0.0006	1.2	2.6
4	0.1	0.3	0.0	0.0	0.0011	1.5	4.2
5	0.1	0.1	0.0	0.2	0.0009	0.9	3.1
8	0.0	0.0	0.3	0.1	0.0008	1.4	1.9
11	0.0	0.7	0.1	0.5	0.0001	0.1	0.7
12	0.0	0.6	0.3	1.1	0.0003	0.4	0.6
13	0.0	1.2	0.1	0.5	0.0004	0.1	0.8
14	0.1	0.1	0.2	0.3	0.0008	1.5	1.9
15	0.0	0.3	0.0	0.1	0.0006	1.2	1.8
16	0.0	0.3	0.0	0.2	0.0005	1.1	3.6
17	0.1	0.2	0.1	0.1	0.0001	1.6	3.0

Table 2 - Results of Ground and Surface Water Samples Analysis at Rockefeller Refuge (December 7-8, 1985)*

Sample	pH 0-14	Turbidity FTU 0-400 FTU	Dissolved Oxygen mg/l	Chloride 0-125 mg/l	Sulfate 0-100 mg/l	Ammonia 0-2 mg/l	Bicarbonate mg/l CaCO3
1	6.5	2	1.1	1280	3.2	1.60	348
3	6.0	27	0.6	5140	620	2.10	72
4	6.2	88	0.8	5390	600	2.70	210
5	6.1	35	1.4	6815	690	1.90	88
8	6.4	69	1.0	6575	780	2.90	112
11	6.2	3	1.0	410	1.8	0.56	286
12	6.5	9	1.1	495	9.0	1.30	330
13	6.1	1	0.7	185	4.6	0.54	290
14	6.2	44	0.8	7710	440	2.10	196
15	6.2	26	1.2	7180	480	2.10	202
16	6.0	48	1.0	4810	320	1.60	162
17	6.4	53	0.9	560	3.6	0.68	310

Sample	Nitrate mg/l	Phosphate mg/l	TOC 1.0 mg/l	Specific Conductance Micromhos	Temperature °C	Depth
1	1.0	.005	15.2	2.4×10^3	14	
3	2.8	.005	0.52	4.1×10^3	13	1'6"
4	3.7	.005	21.0	4.8×10^3	14	1'2"
5	2.6	.005	6.8	4.9×10^3	14	5'6" below bridge
8	4.7	.005	25.5	4.8×10^3	14	4'10" below bridge
11	1.0	.005	5.1	2.0×10^3	19	
12	2.2	.005	3.6	2.4×10^3	14	
13	1.9	.005	4.9	1.6×10^3	16	2'2"
14	3.6	.005	31.2	4.8×10^3	16	1'9"
15	3.9	.005	21.6	5.3×10^3	16	1'4"
16	4.3	.005	29.8	3.8×10^3	15	
17	2.3	.005	14.3	2.7×10^3	13	

*Samples were collected between 3:30 pm and 7:10 pm on December 7, 1985. The weather conditions included overcast skies, mild wind and an average temperature of 60-65°F, with high groundwater and surface water levels.

Table 3 - Results of Ground and Surface Water Samples Analysis at Brazoria (December 7-8, 1985)*

Sample	pH 0-14	Turbidity FTU 0-400 FTU	Dissolved Oxygen mg/1	Chloride 0-125 mg/1	Sulfate 0-100 mg/1	Ammonia 0-2 mg/1	Bicarbonate mg/1 CaCO3
18	6.7	2	1.0	525	30.4	0.35	402
19	6.7	9	0.8	295	32.2	0.27	298
20	6.2	47	1.1	4300	280	0.34	144
21	6.4	10	1.4	605	22	0.43	388
22	6.3	15	0.9	4430	370	1.46	226
23	6.2	14	1.0	11200	1260	1.95	228

Sample	Nitrate mg/1	Phosphate mg/1	TOC 1.0 mg/1	Specific Conductance Micromhos	Temperature °C	Depth
18	2.0	.005	25.9	2.2×10^3	21	3'3½"
19	2.0	.005	34.6	2.0×10^3	22	1'11"
20	2.7	.005	21.8	2.2×10^3	17	1'2"
21	2.5	.005	31.4	2.2×10^3	21	4'
22	2.9	.005	14.3	2.9×10^3	17	10" below dock
23	2.6	.005	4.5	1.4×10^4	16	1'11" below dock

Sample	Cr ppd 0.001 mg/1	Na ppm 0.002 mg/1	K ppm 0.005 mg/1	Mg ppm 0.0005 mg/1	Ca ppm 0.01 mg/1	Mn ppm 0.01 mg/1
18	0.65	316	1.53	15.52	84.51	0.01
19	0.89	230	0.81	12.13	83.22	0.03
20	0.34	2120	19.18	19.35	76.56	0.15
21	1.26	325	1.52	10.42	80.25	0.05
22	1.04	3105	36.27	21.63	58.74	0.16
23	1.16	6550	38.52	19.62	86.27	0.03

*Samples were collected between 10:30 am and 1:00 pm on December 7, 1985. Weather conditions included overcast skies, damp, mild winds and an average temperature of 60-65°F with high groundwater and surface water levels.

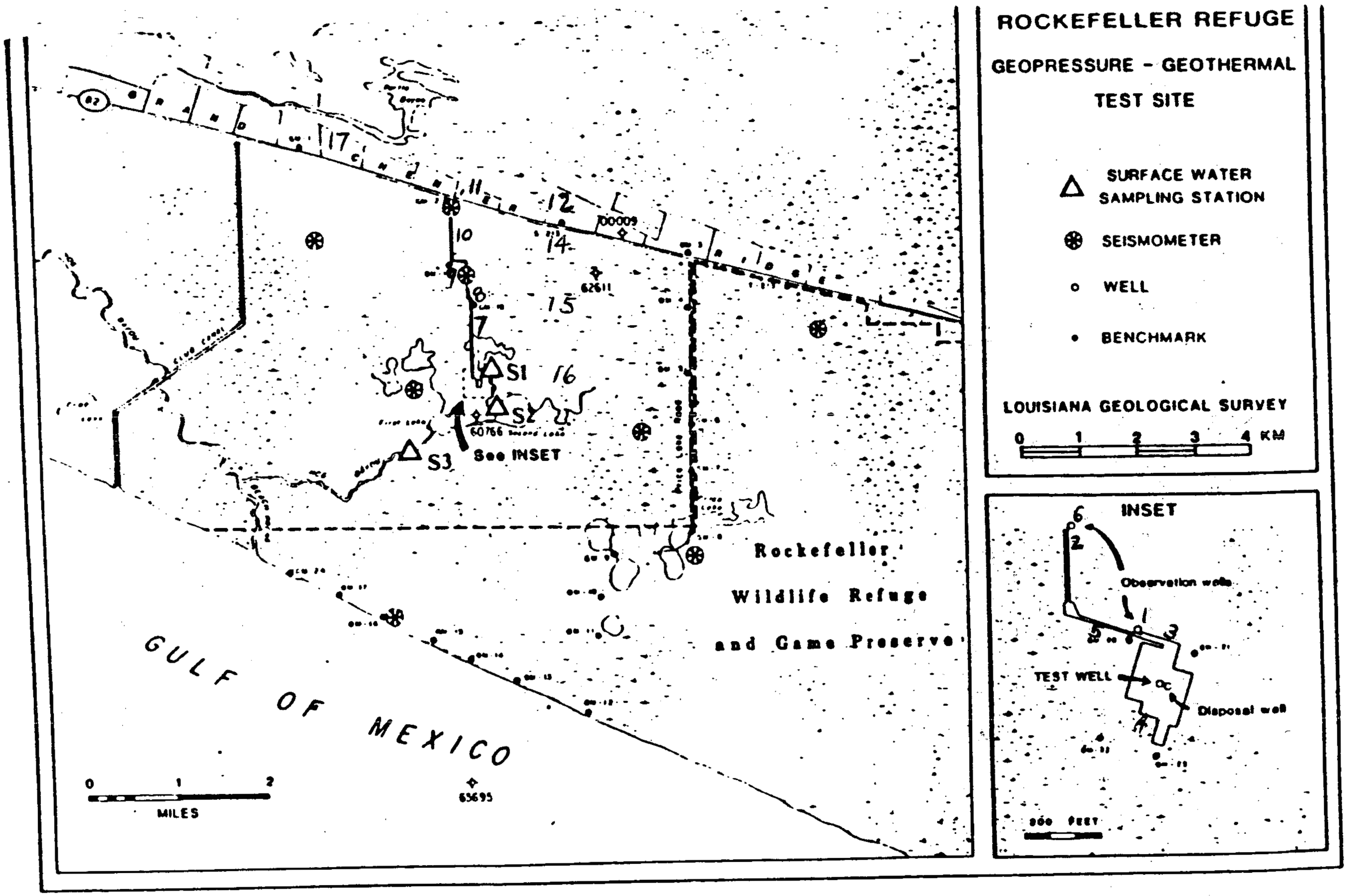


Fig 3. Area map of Rockefeller Refuge geopressured-geothermal test site showing locations of parameter observation stations.

S-9965

BRUSHES — Flask, Convex.
Mounted on a preformed durable plastic handle with bristles twisted in wire. Flexible brush section adapts itself to the curvature of the flasks.

Cat. No.	*For Flask Capacity, mL*	*Bristle Section Length, mm*	*Bristle Section Diameter, mm*	*Total Length, mm*	***Price/ Each***
S-9965-A	250	89	35	300	**2.00**
S-9965-B	500	100	38	360	**2.10**
S-9965-C	1000	127	44	430	**2.50**

12 or more, 10% discount.

S-9975

S-9975

BRUSH — Flask, Offset.
Made of white unbleached hog bristle twisted into galvanized wire and mounted on an offset of the preformed plastic handle. Effective in reaching shoulder surfaces of flasks and bottles. Total length, 406 mm; length of bristle section, 102 mm; diameter of bristle section, 38 mm.

Each **2.75**
12 or more, 10% discount.

S-9980

S-9980

BRUSH — Test Tube, Radial Tuft, Large, Nylon.
For test tubes from 19 to 25 mm diameter. Made of stiff nylon bristles twisted into galvanized wire. Radial tufted end. The tufted tip covers all parts of the test tube. Total length, 280 mm; length of bristle section, 100 mm; diameter of bristles, 35 mm.

Each **1.65**
12 or more, 10% discount.

S-9985

BRUSH — Test Tube, Radial Tuft, Large.
For test tubes from 19 to 25 mm in diameter. Made from selected bristles heavily filled in tightly twisted heavy gauge galvanized wire with radially tufted tip. Total length, 300 mm; length of bristle section, 95 mm; diameter, 35 mm.

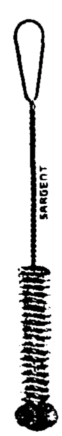
Pkg of 12 .... **9.72**
12 or more pkg, 10% discount.

S-9990

S-9990

BRUSH — Test Tube, Radial Tuft, Medium, Nylon.
Best quality nylon fiber, having wearing properties superior to bristles, with less absorption of moisture for retention of flexibility. For test tubes from 16 to 19 mm in diameter. Total length, 230 mm; length of bristle section, 89 mm; diameter, 19 mm.

Pkg of 12 .... **9.60**
12 or more pkg, 10% discount.



S-9995

S-9995

BRUSH — Test Tube, Radial Tuft, Medium.
For tubes 16 to 19 mm in diameter. Bristles twisted into heavy gauge galvanized wire with radial tuft end. Total length, 250 mm; length of bristle section, 80 mm; diameter, 20 cm.

Pkg of 12 .... **7.20**
12 or more pkg, 10% discount.

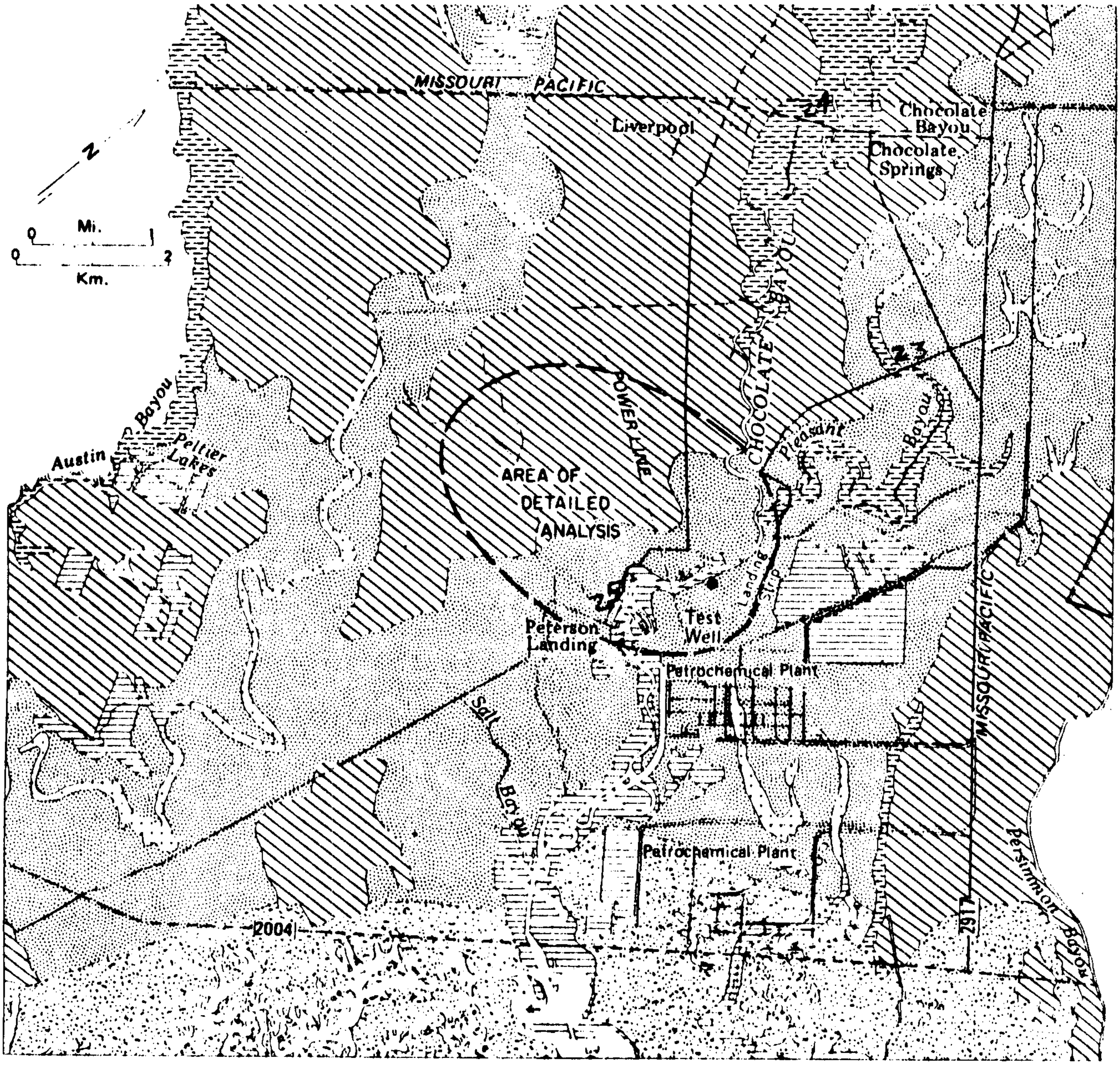


Fig.(4-a)

EXPLANATION

Distributary and fluvial sands and silts, including levee and cravasse splay deposits

Interdistributary mud, including bay and floodbasin facies

Marine deltaic sand, delta front and reworked delta facies; may be veneered by thin marsh or lacustrine mud

Abandoned channel and course, mud filled

Tidal creek, fresh to brackish-water marsh-covered, mud-filled

Small active headward-eroding streams, tree-covered, alluvium, sand, silt, mud, alluvium absent locally

Undifferentiated reservoirs, ponds, spoil, fresh to brackish marsh, mud and local sand substrate

Environmental geologic map of the Brazoria County prospect area. Map units depicted are Pleistocene to Recent. (Modified from Fisher and others, 1972)

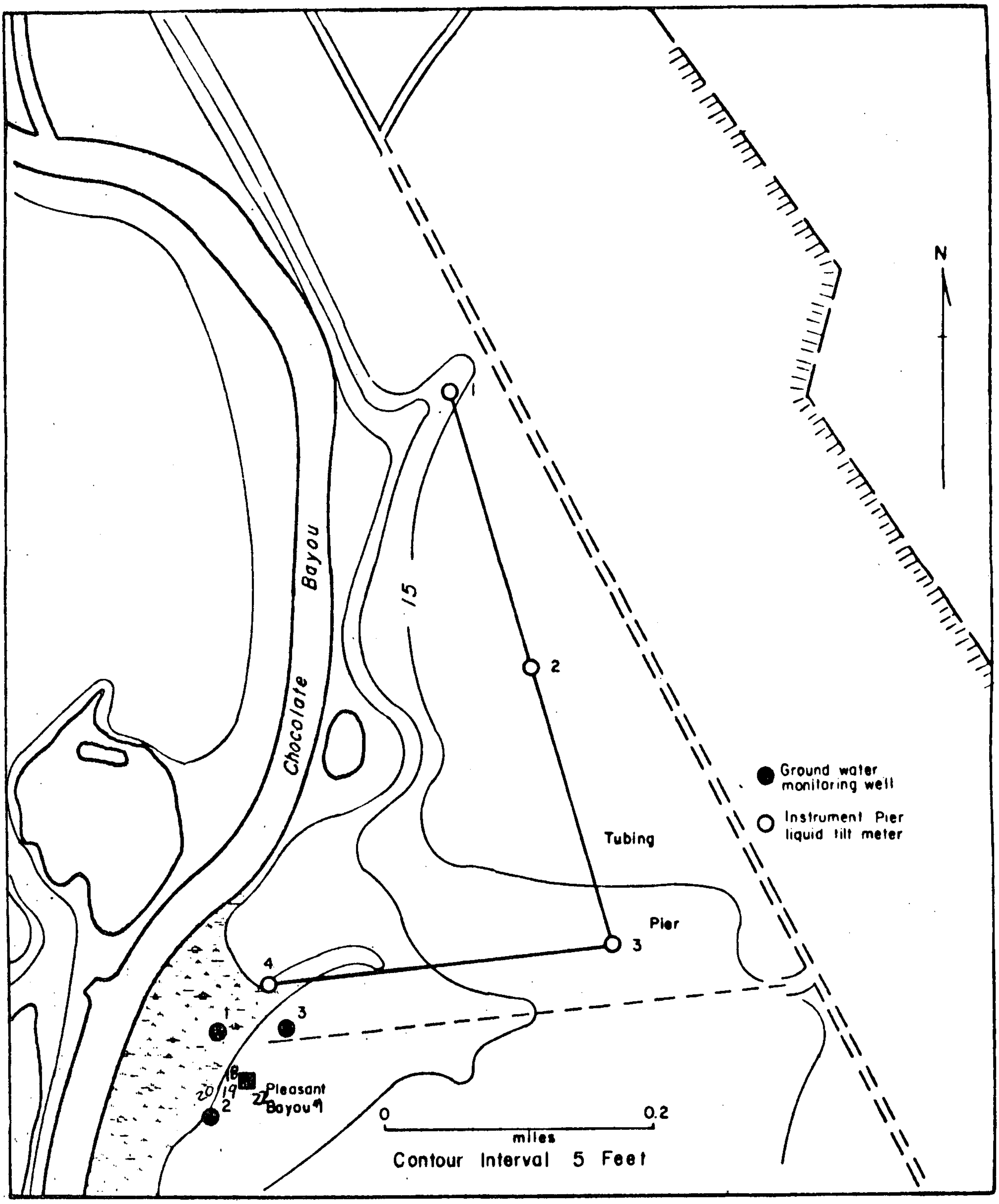
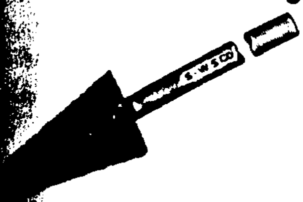


Fig 4. Location of ground-water monitoring wells and multiliquid tilt meter line.

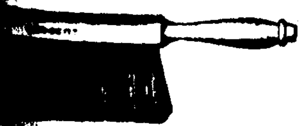


S-9850
BRUSH — Conical, Radial Tuft, Wire Mounted, Wood Handle, Large.
For use principally in cleaning S-84126 to S-84142 Imhoff water sedimentation cones. Constructed of black bristles and heavy brown fiber tightly twisted into heavy gauge galvanized wire with wood handle. Conical shape with heavy radial tuft designed to reach lower extremities of the sedimentation cones. The brush section is 248 mm, the first 102 mm of black bristle, the remaining 146 mm of brown fiber. Diameter of the brush at the end is 19 mm, tapering back to 102 mm. The fan style tip has a radius of 45 mm. The handle is 381 mm.

Each **7.85**
12 or more, 10% discount.

S-9855
BRUSH — Cement Briquette, Brass Wire Bristles.
For cleaning briquette molds or plates. With four rows of brass wire bristles mounted in a wood handle. Total length, 260 mm; length of bristle section, 130 mm; width of bristle section, 22 mm; length of bristles, 28 mm.

Each **3.95**



S-9865
BRUSH — Counter, Large, Superior Grade.
For dusting tables, desks, etc. Widely flared 100% horsehair bristles are staple set into natural lacquered hardwood block. Handle has a hole for hanging. Total length, 381 mm; length of brush face, 229 mm; maximum width of brush face, 83 mm; height of bristles, 64 mm.

Each **7.65**
12 or more, 10% discount.

S-9875
BRUSH — Counter, Medium.
Similar to S-9865 but designed for dusting heavier particle accumulations. Bristles are tampico, wide, flared end, staple set into natural lacquered hardwood block with hang up hole. Total length, 356 mm; length of brush face, 203 mm; width of brush face, 63 mm; height of bristles, 64 mm.

Each **4.40**
12 or more, 10% discount.

S-9880
BRUSH — Scrubbing.
With 4 rows of stiff tampico bristles for fine scrubbing mounted in a wood block. Block length, 184 mm; block width, 60 mm; height of bristles, 25 mm.

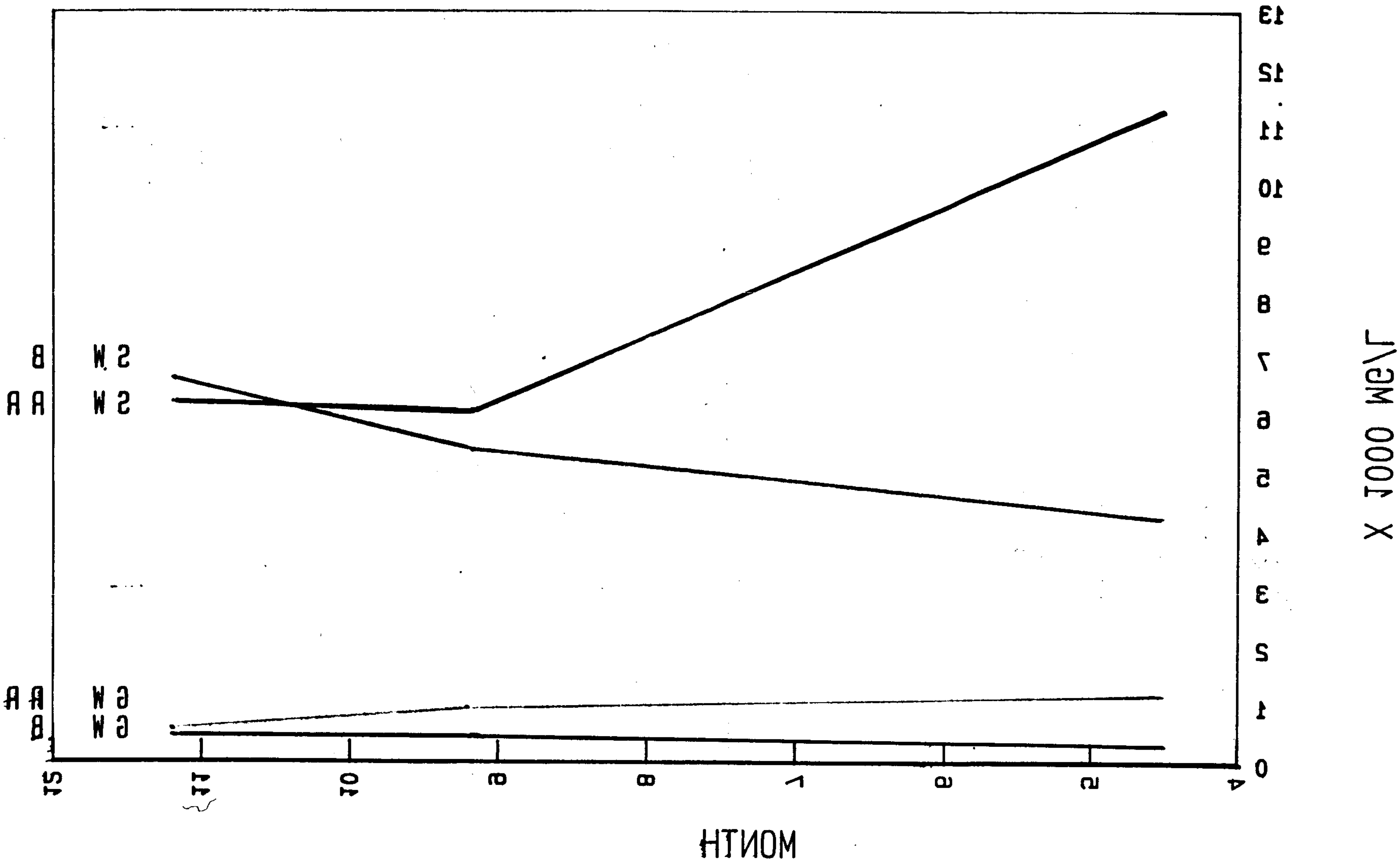
Each **2.50**
12 or more, 10% discount.

S-9885
BRUSHES — Buret.
With bristles twisted in flexible galvanized handles of heavy gauge wire and with large handle loops. The small size is for 25 mL and 50 mL burets, and the large one for 75 mL and 100 mL sizes. For smaller buret brush, see S-9905.

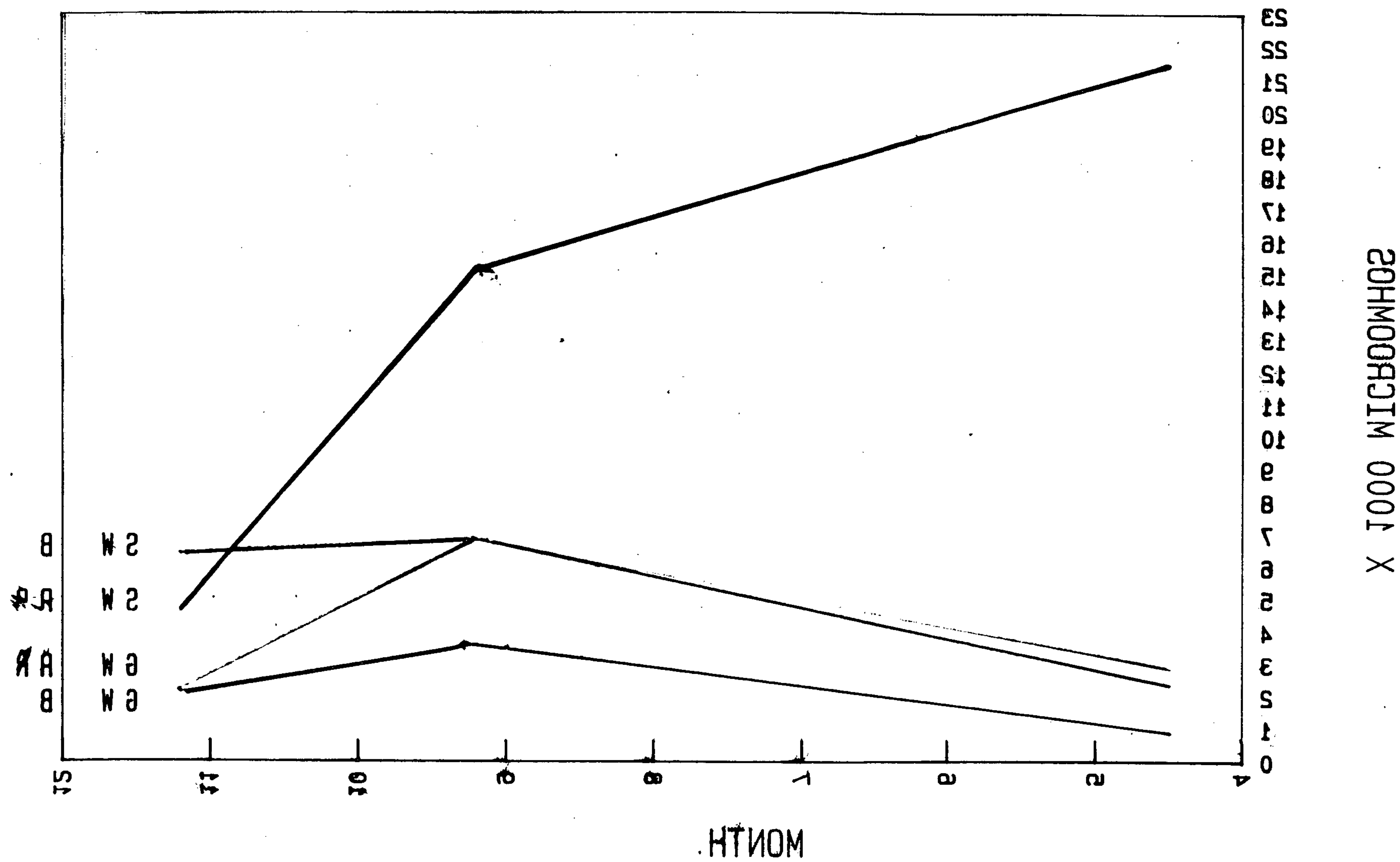
Cat. No.	Total Length, mm	Bristle Section Length, mm	Bristle Section Diameter, mm	Price/Pkg	of
S-9885-A	760	76	13	**9.00**	12
S-9885-B	910	127	32	**13.44**	12

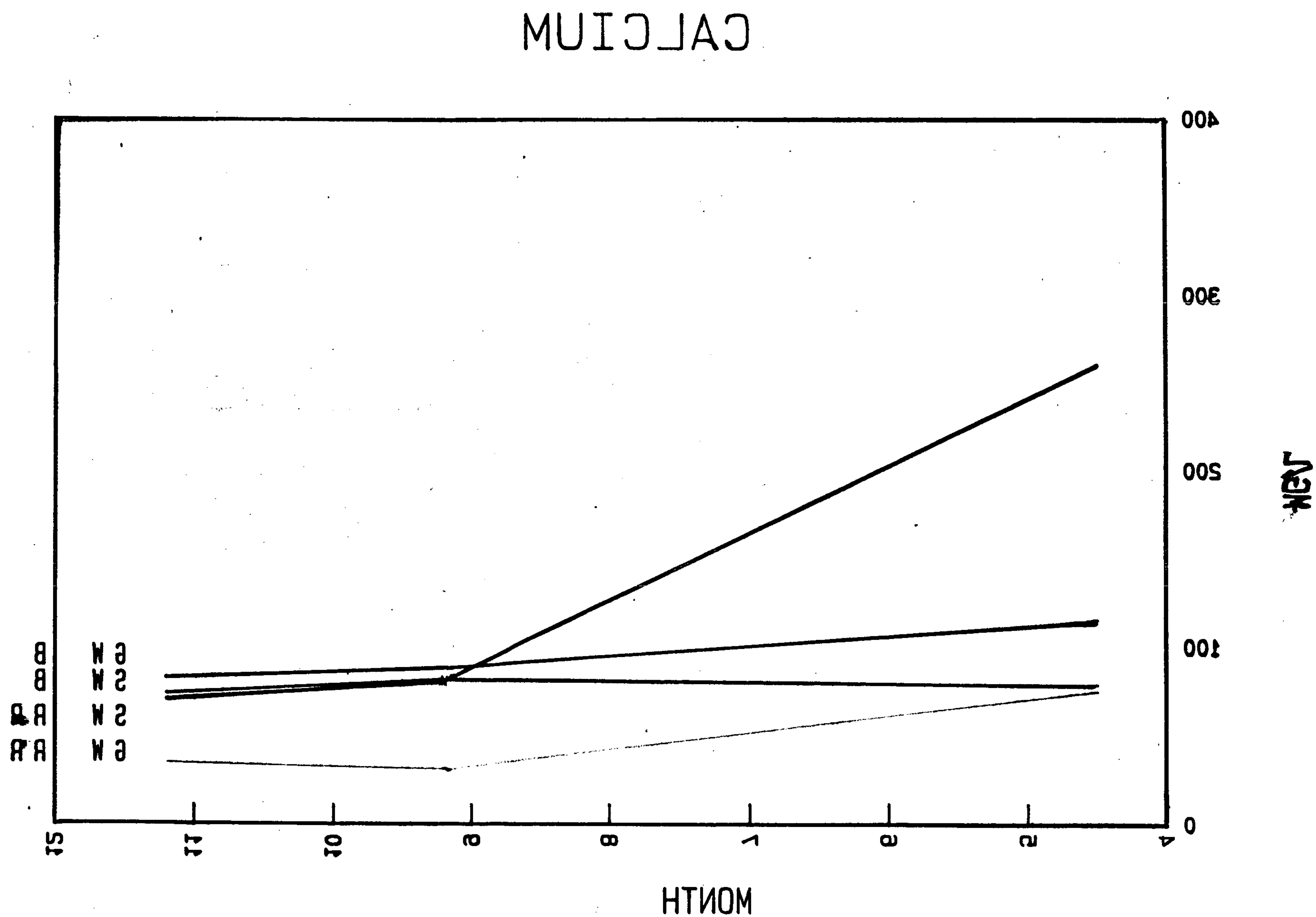
12 or more pkg, 10% discount.

CHLORIDE

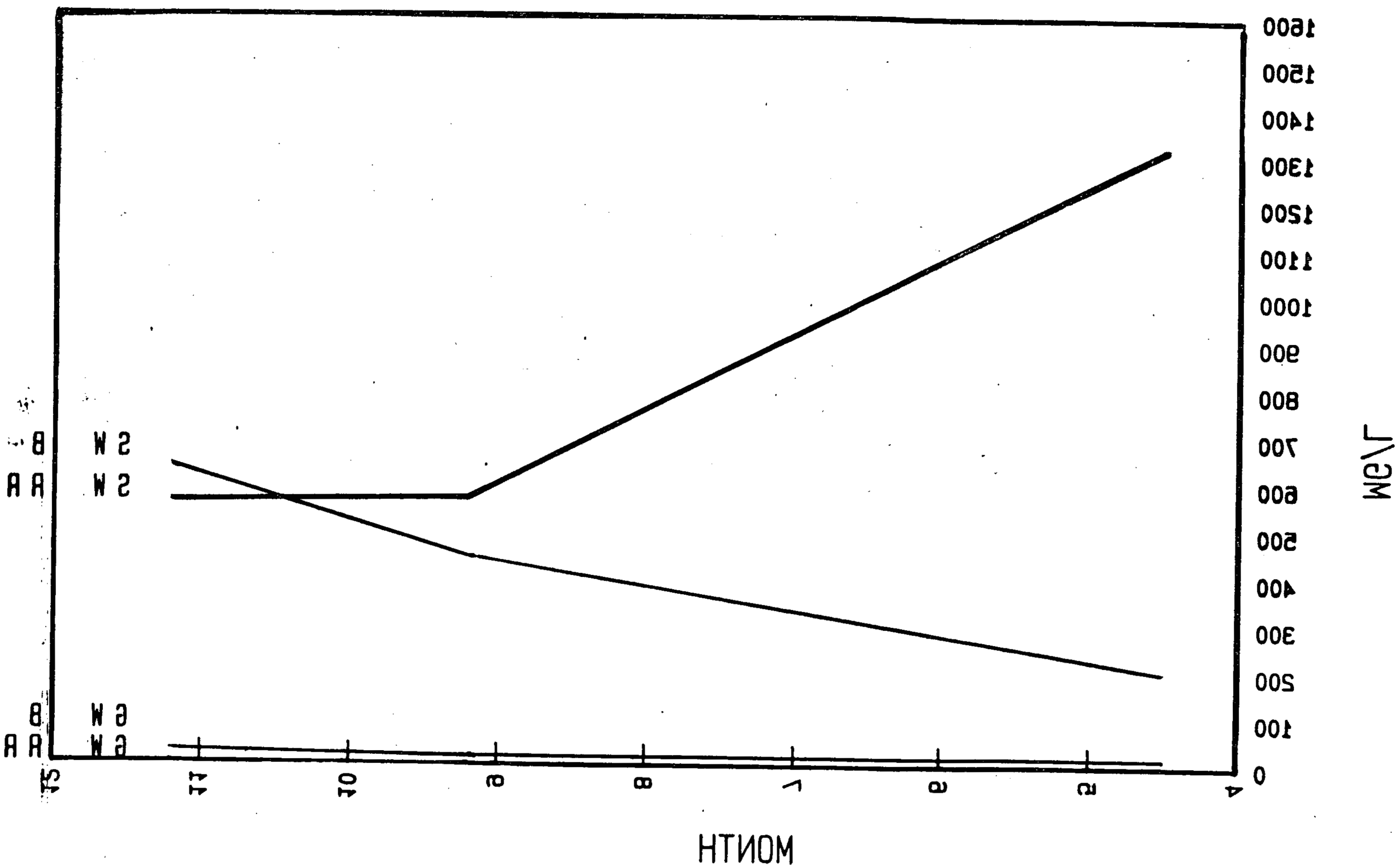


SPECIFIC CONDUCTANCE

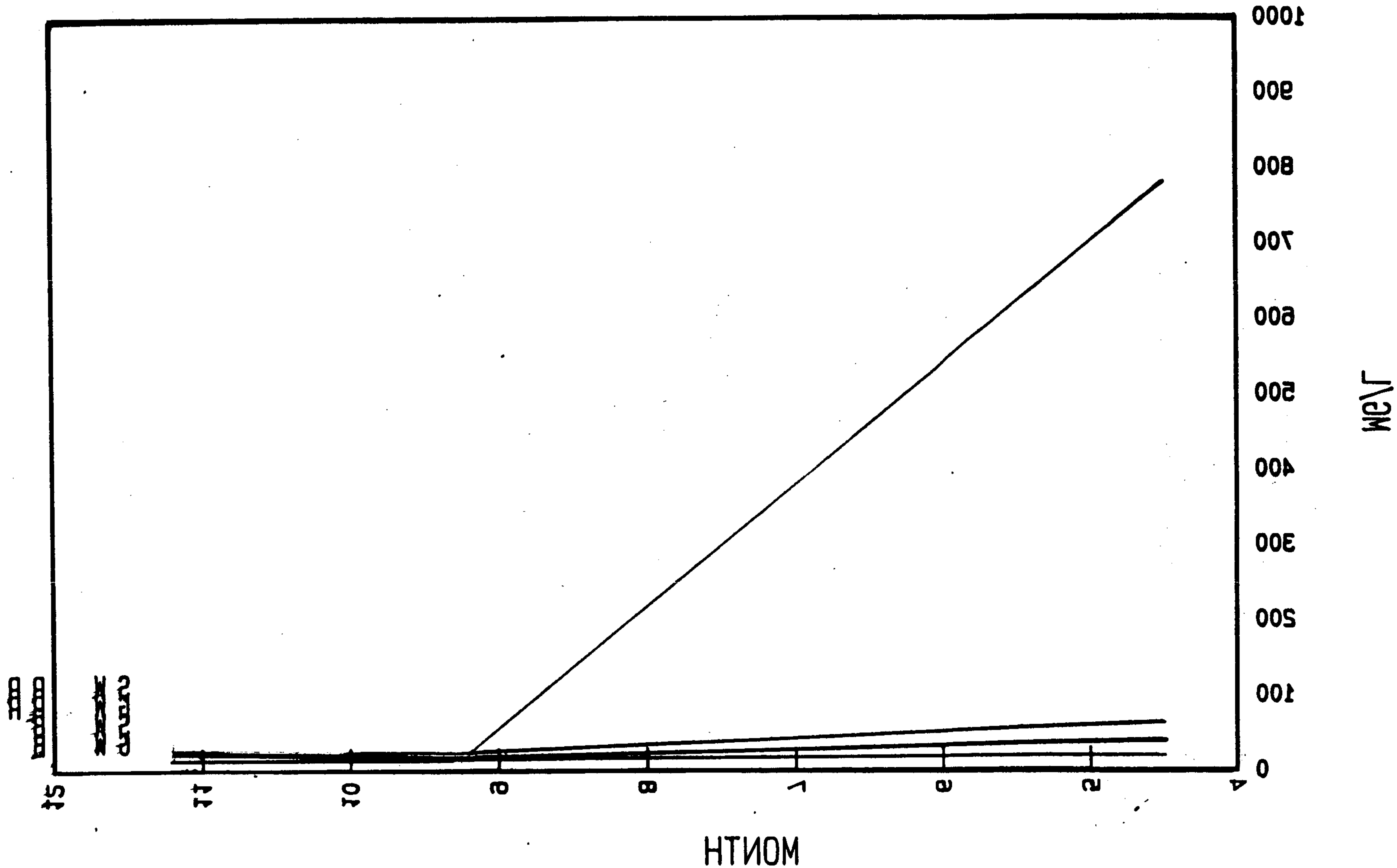



CALCIUM
MEQ/L
400
300
200
100
0
MONTH
4
5
6
7
8
9
10
11
12
6 W B
5 W B
5 W R
6 W R

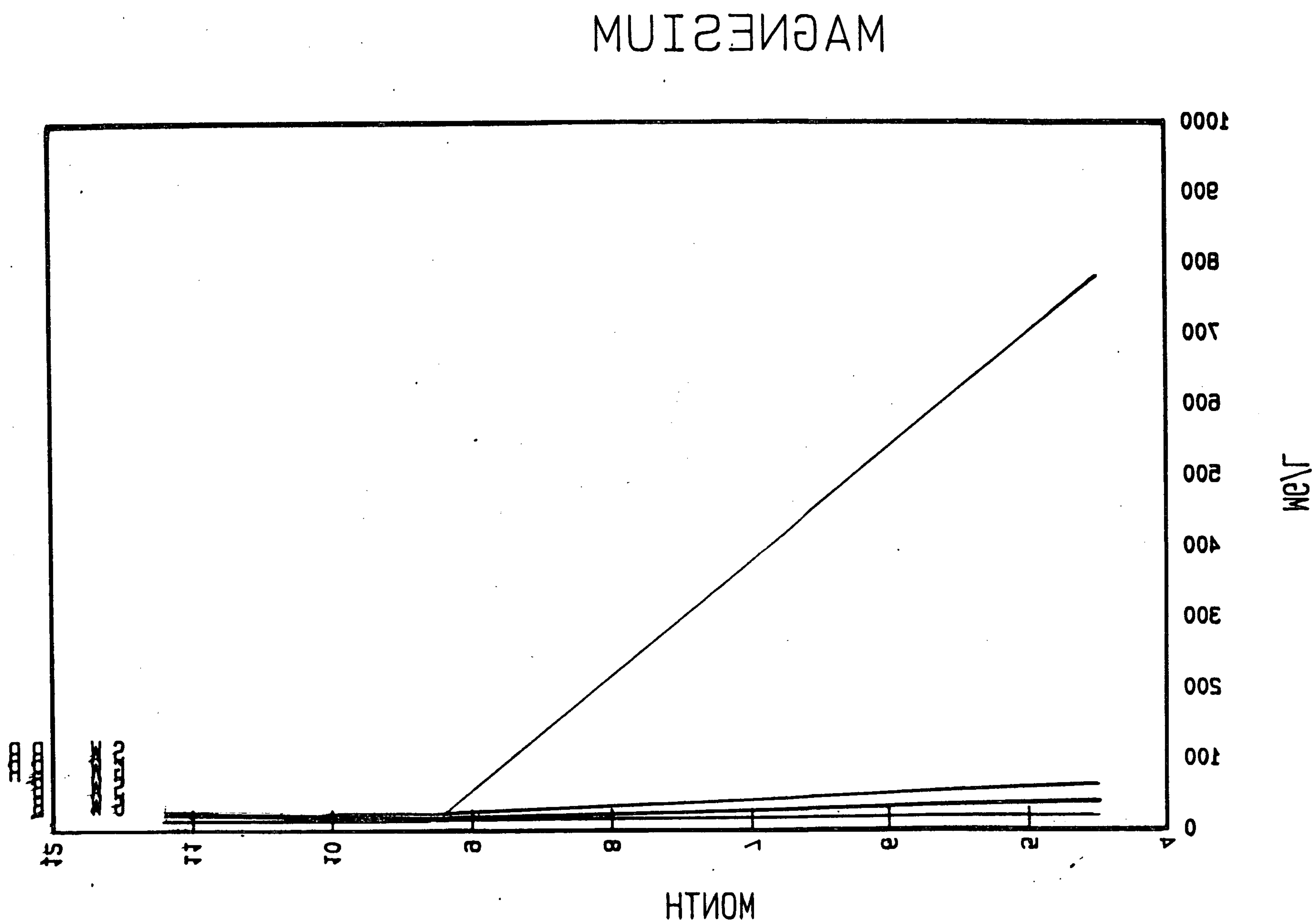
SULFATE


MG/L
MONTH
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
4
5
6
7
8
9
10
11
12
S W
S W
G W
G W
B
R R
B
R R

MAGNESIUM



1000
900
800
700
600
500
400
300
200
100
0
MG/L
4
5
6
7
8
9
10
11
12
MONTH



MAGNESIUM
MG/L
0
100
200
300
400
500
600
700
800
900
1000
MONTH
4
5
6
7
8
9
10
11
12

K. APPENDIX 11

ANALYSIS OF HYDROCARBONS FROM DOE WELLS
COMPLETE WRITE-UP OF WORK

D. KEELEY/J. MERIWETHER - USL

AROMATIC HYDROCARBONS ASSOCIATED WITH GEOPRESSURED BRINES

Report of research tasks being conducted by

Dr. Dean F. Keeley and Dr. John R. Meriwether

University of Southwestern Louisiana

A. DETERMINATION OF THE SOLUBILITIES OF SELECTED AROMATIC HYDROCARBONS IN SODIUM CHLORIDE SOLUTIONS OF DIFFERING IONIC STRENGTHS.

1. Reason for Conducting Research: The scientific literature contains numerous values for the solubilities of specific aromatic compounds in water at room temperatures. Solubility values for the same compounds in NaCl brines of different concentrations are less available. Values in brines of different concentrations, at different temperatures, employing the same technique by the same laboratory are simply nonexistent.

Since geopressured brines from the U.S. Gulf Coast region apparently all contain a complex mixture of aromatic hydrocarbons, it was deemed appropriate, as part of the overall geopressured program, to undertake the rather ambitious project of determining the solubilities of the compounds in the cryocondensates. The initial phase has involved determining the solubilities of the six most abundant hydrocarbons: benzene, toluene, ethylbenzene, and the three isomers of xylene as functions of ionic strength and temperature.

2. Method Selection: A critical review of the many methods which have been used to determine solubilities of compound with appreciable vapor pressures indicated that only one method was not subject to the difficulties caused by the partition of such substances between the solvent and any free gas space above the solvent. This method was a technique (Massaldi and King 1973) based on headspace analysis. Headspace analysis involves the analysis, usually by gas chromatograpy, of the vapor which is in equilibrium with a condensed phase (eg. vapor above wine).

3. Theoretical: Since the chemical potential, u_i, of any substance has the same value in all of its saturated solutions. It follows that if the substance has an appreciable vapor pressure that its partial vapor pressure above any saturated solution will be equal to the vapor pressure of the pure substance.

If a substance has a limited solubility it will tend to obey

Henry's law,

$$X = k\ p \tag{1}$$

where p is the partial pressure of the substance above the solution when its mole fraction is X, and k is the Henry's law constant for the system at the prevailing temperature. The agreement with Henry's law increases as X -> 0. At saturation it take the form

$$X^\circ = k\ p^\circ \tag{2}$$

where the zeroed quantities refer to saturation, hence p° refers to the vapor pressure of the pure substance.

If one designs a set of experiments which effectively measures the partial pressure, p, of a substance above its solutions as a function of its mole fraction, X, in the solutions then extrapolation to p° will yield X°.

4. <u>Multiple Injection Interrupted Flow (MIIF) Method</u>: We have developed a modification of the Massaldi and King method which allows us to determine the solubility of any substance having an appreciable vapor pressure, in any solvent, containing any additional solutes in any amount.

The method consists in preparing a number of samples containing varying amounts of a compound so as to have it present at varying partial pressures. These samples are analyzed by headspace gas chromatography (HGC) to obtain the GC response as a function of partial pressure:

$$A = C\ p \tag{3}$$

where A is GC area response and C is a constant containing all pertinent GC correlation parameters. Extrapolation of this data to p° allows us to evaluate the value of A°.

A second set of samples containing varying amounts of the compound and a fixed amount of solvent are similarly analyzed. Computing the amount of compound needed to produce a response A°, will yield the amount of compound needed to produce system saturation, n°_t, which is defined by the relationship

$$n^\circ_t = n^\circ_v + n^\circ_s \tag{4}$$

where n°_v and n°_x are the amount of compound in the vapor and solvent phases, respectively. Since n°_v can be computed from A°

and the system volume, and since $n°_t$ is the total amount of compound needed to give a system response $A°$, $n°_x$, the solubility, can be computed. It should be noted that this modification of the Massaldi and King method precludes the difficulties that are inherent in having to use saturated solutions.

The name "multiple injection interrupted flow (MIIF)" method comes from the actual way in which the values of A, the GC area response are obtained (Keeley, Hoffpauir, and Meriwether 1986). We believe that the MIIF technique will find broad application. It is ideally suited to looks at phenomenon such as synergistic effects in solubility.

5. Results to Date: To date we have determined the solubilities of benzene, toluene, ethylbenzene, ortho-, and meta-xylene in NaCl solutions of ionic strengths raging from 0 to 4 (ie. 0 to 4 molar) at 25.00 °C. We have also computed the Henry's law constants, partition coefficients, and molar activity coefficients of these solutes in the indicated solutions. Work is in progress on meta- and para-xylene at 25.00 °C and work is commencing on all of the hydrocarbons at 50.00 °C.

B. DISTRIBUTION COEFFICIENT MEASUREMENTS.

1. Theory: Since a volatile solute tends to obey Henry's law in dilute solutions and since the partial pressure of the solute above solutions which are in equilibrium is the same, it follows that

$$X_2 / X_1 = k_2 / k_1 = K \qquad (5)$$

where K is the distribution coefficient.

2. Method: The method used to obtain the Henry's law constants for the hydrocarbons in an oil is the same as described in Part A. Since the oil used must be initially free of the compounds of interest and since there is no "standard" reference oil for this type of determination we have adopted a synthetic oil, Mobil-1, to be our standard.

3. Results to Date: To date we have determined the partition coefficients for benzene, toluene, ethylbenzene, ortho- and meta-xylene between the "standard' oil and brines with ionic strength ranging from 0 to 4 at 25.00 °C. Work is in progress on meta- and para-xylene at 25.00 °C and commencing on the hydrocarbons at 50.00 °C.

It should be noted that this particular phase of our research has ramifications, and has attracted interest, from outside the geopressured energy area. The compounds being studied are potential environmental hazards. Since a number of crude oils contain aromatic hydrocarbons in substantial amounts, these distribution values, as well as the partition values calculated in conjunction with Part A, will be of value in calculating the environmental impact of an aromatic-rich oil spill.

C. cryocondensate.

1. Collection method: The method of collecting and quantifying the cryocondensate can be found in "The Proceeding of the Sixth Gulf Coast Geopressured-Geothermal Energy Conference" (Keeley and Meriwether, 1985).

2. Composition: The composition of the cryocondensate can be found in "The Proceeding of the Sixth Gulf Coast Geopressured-Geothermal Energy Conference" (Keeley and Meriwether, 1985).

3. Results to date: The results to date are shown in the graph on the following page.

4. Conjecture: The Gibbs free energy difference, ^G, associated with a solute at two concentrations, C_1 and C_2, is given by

$$\text{^}G = - R\ T \ln (C_2 / C_1) \qquad (6)$$

where R = the gas constant and T = the absolute temperature.

The cryogenic condensate concentration gradient we have observed for the Gladys McCall well would yield a ^G value of ~ - 577 cal/mol. With any reasonable permeability, such a concentration gradient could not exist and homogeniety would occur via diffusion in a time span short compared to geologic times. Several possible explanations might explain our observations:

a.) Catagenesis: The aromatic compound which comprise the cryocondensate are still being produced by catagenesis from the residual hydrocarbons (ie. oil) known to be present in the formation. If this is the case then a concentration gradient would exist between the oil location(s) and the regions devoid of oil in the formation. If this is true then the recent concentration trend might well be an indicator of another period of oil production from the Gladys McCall well.

b.) Adsorption: Since the components of the cryocondensate are primarily aromatic in nature it is possible that they may be adsorbed by pi-electron interaction to the particles of the formation. Such a process could produce a concentration gradient, but it would probably also yield a composition gradient, which has not been observed.

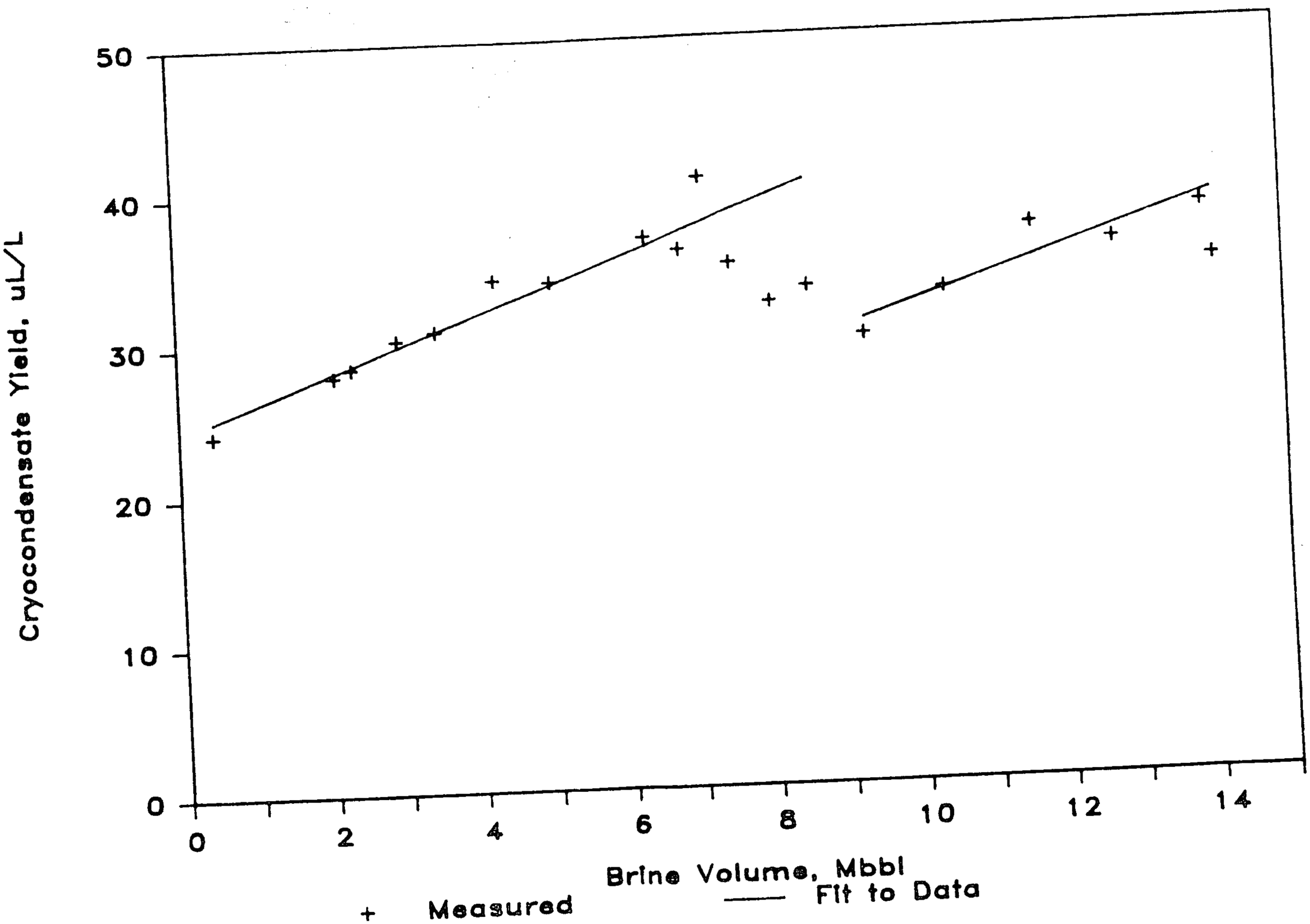
c.) Free Gas: If the formation contained free gas the concentration of cryocondensate components in the gas would be significant. If the free gas production increased with cumulative brine volume it would appear as an increase in the cryocondensate concentration. This process would also be expected to show a composition change of the cryocondensate with cumulative brine volume since the partition coefficients of the compound which comprise the cryocondensate are different.

D. REFERENCES:

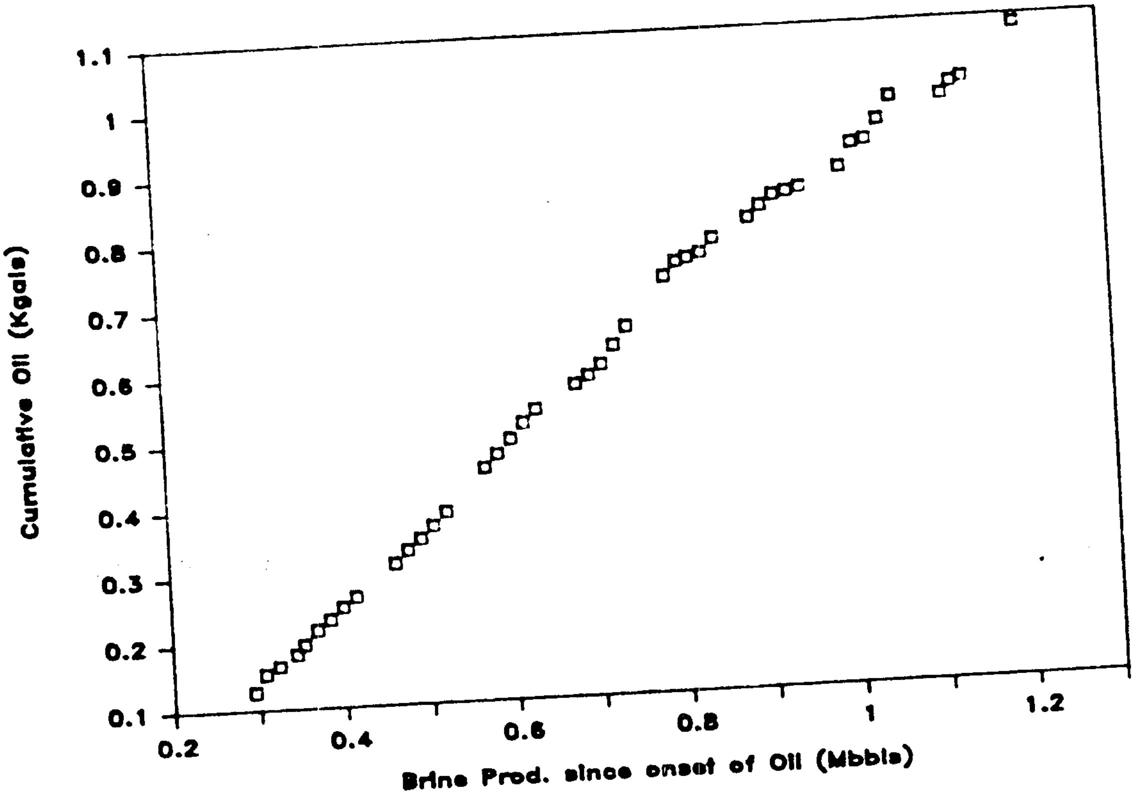
H. A. Massaldi, and C. J. King J. Chem. Eng. Data 1973, 18(4), 393.

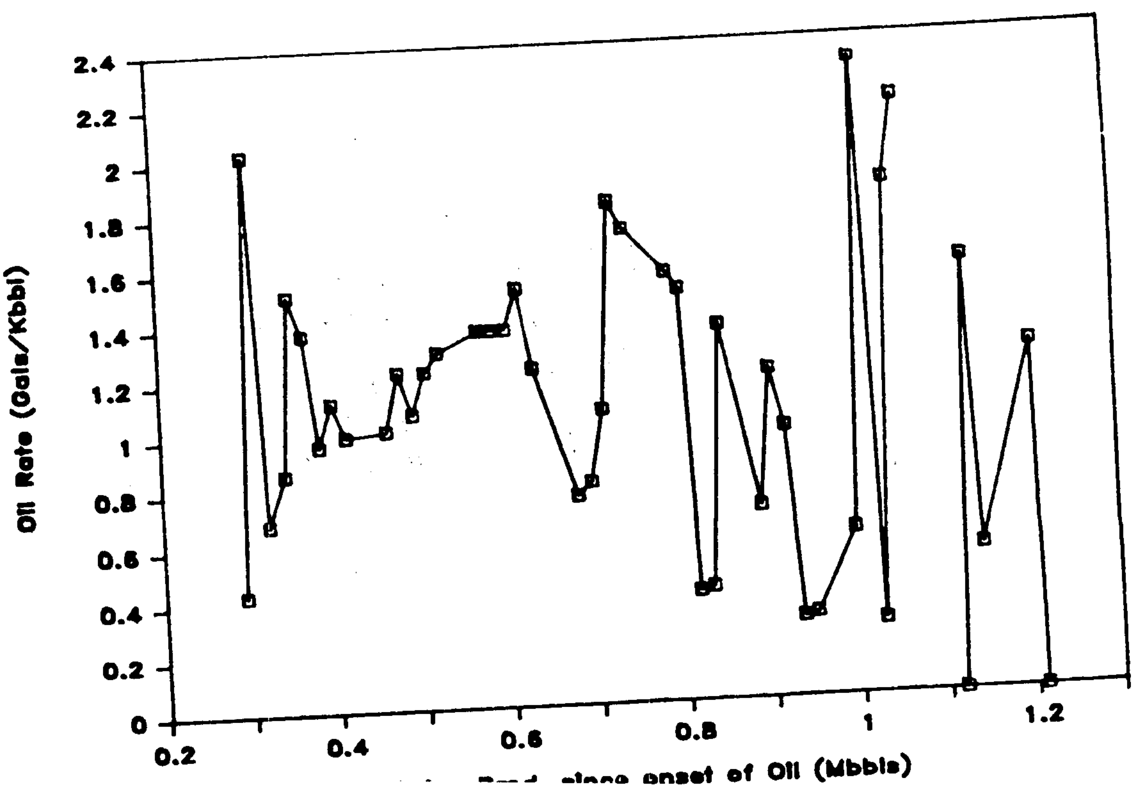
D. F. Keeley, M. A. Hoffpauir, and J. R. Meriwether 1986, submitted for publication in J. Am. Chem. Soc.

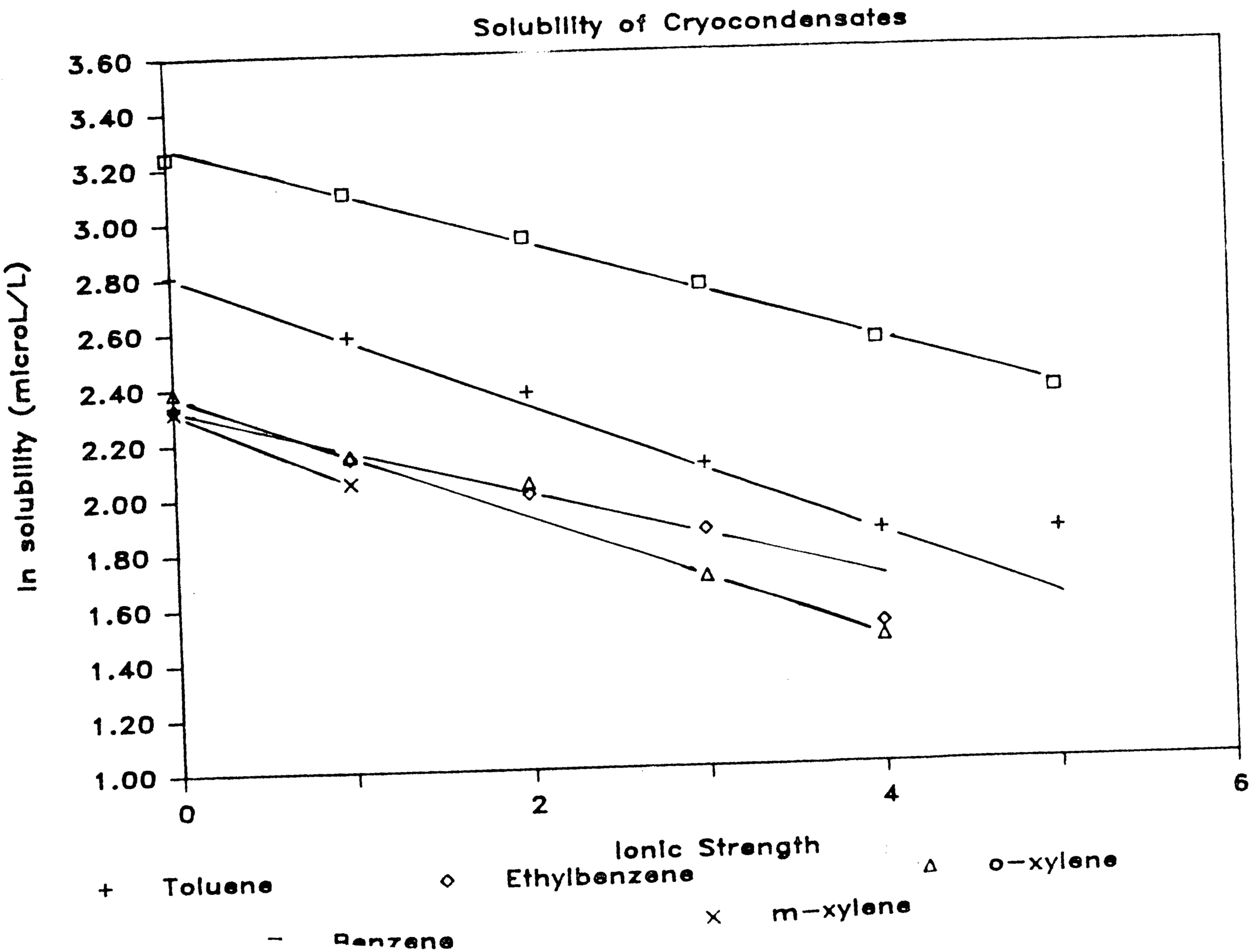
Gladys McCall Well

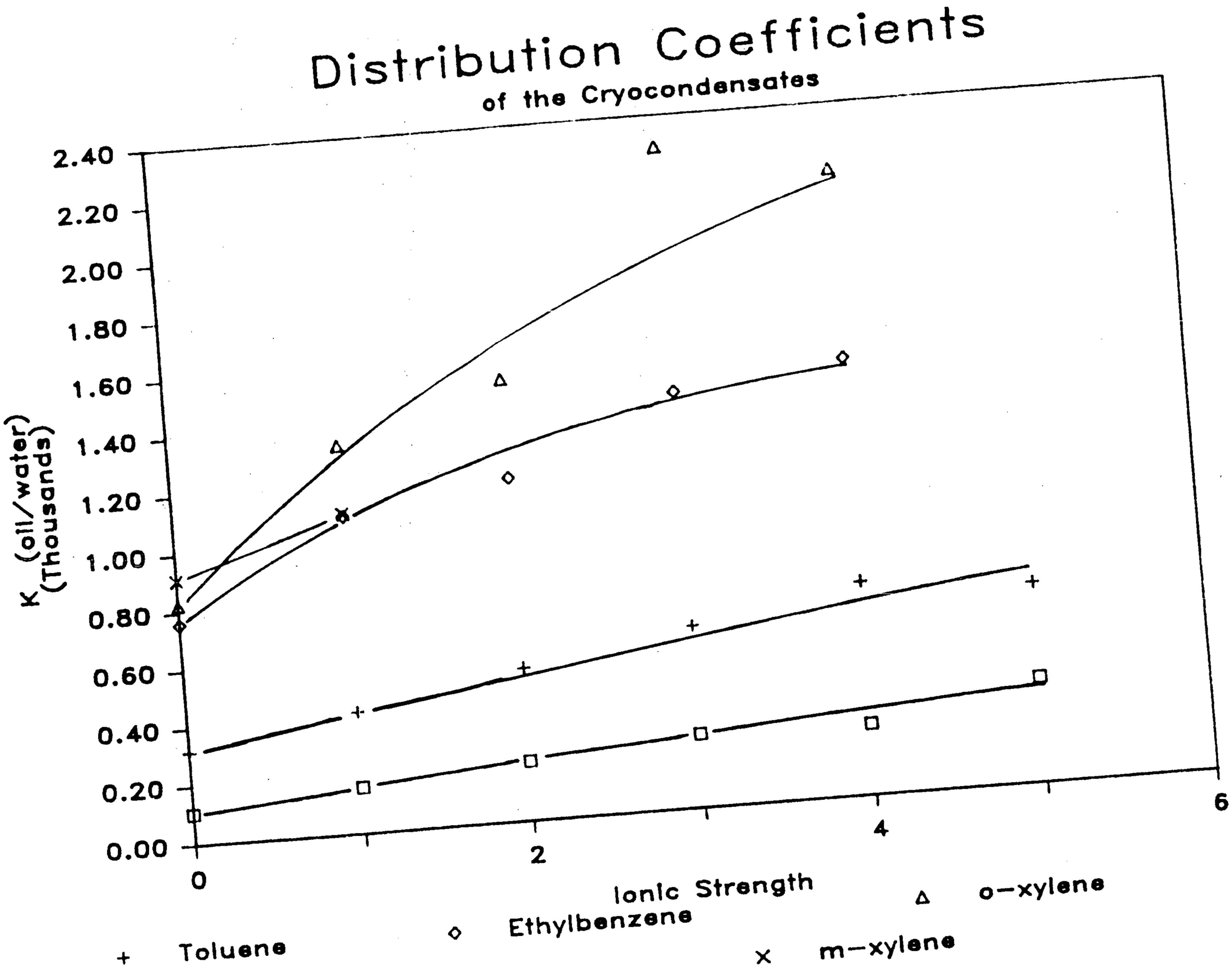


Gladys McCall Well






Solubility of Cryocondensates
ln solubility (microL/L)
3.60
3.40
3.20
3.00
2.80
2.60
2.40
2.20
2.00
1.80
1.60
1.40
1.20
1.00
0
2
4
6
Ionic Strength
+ Toluene
◇ Ethylbenzene
Δ o-xylene
× m-xylene
– Benzene



Distribution Coefficients
of the Cryocondensates
K (oil/water) (Thousands)
2.40
2.20
2.00
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0
2
4
6
Ionic Strength
+ Toluene
◇ Ethylbenzene
× m-xylene
△ o-xylene

L. APPENDIX 12

LOG ANALYSIS IN GEOPRESSURED WELLS
ESTIMATION OF MUD FILTRATE RESISTIVITY

M. DORFMAN/T. LOWE/H. DUNLAP - UTA

In Press - "Log Analyst"
Feb 86

Estimation of Mud Filtrate Resistivity in Fresh Water Drilling Muds

Tom A. Lowe and H. F. Dunlap

ABSTRACT

Accurate values of R_{mf} as a function of depth are needed when calculating formation water resistivity from the S.P., when calculating formation factor and porosity from short investigation resistivity logs, and when interpreting the results of the repeat formation tester. Recent work has shown that the commonly used values for R_{mf} obtained from log header data are unreliable, due to large short term variations in R_m and R_{mf}. The best way to obtain R_{mf} is to measure it daily, but this is almost never done, and cannot be done on wells which have already been drilled. In some wells, however, daily measured values of R_m and mud density, but not R_{mf}, are available from mud logging units. Such data is also available from an increasing number of wells using "measurement while drilling" (MWD) systems. For these wells, we have found that accurate values of R_{mf} can be obtained using a modified form of Overton & Lipson's correlation, $R_{mf} = C(R_m)^{1.07}$, where C is an empirical function of mud density, provided that measured values of R_m and mud density are used rather than log header derived values. Overton's original correlation was for non-lignosulfonate muds, but we find that it works about as well for today's widely used lignosulfonate muds. The correlation which we recommend, based on Overton's original, non-lignosulfonate data plus considerable new data we have obtained for lignosulfonate muds, is

$$\log_{10}\left(\frac{R_{mf}}{R_m}\right) = .396 - .0475\ \rho_m \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

where ρ_m is mud density in pounds per gallon. For $.1 < R_m$ @ 75°F $<$ 2.0 ΩM, this correlation gives a lower % std deviation relative to measured values of R_{mf} (26%) than other commonly used methods of estimating R_{mf} such as estimating it from log header R_{mf} data, (34%); using $R_{mf} = .75\ R_m$, (69%); and using the Overton correlation with log header R_m and ρ_m data, (67%). In the two wells where we believe we have the best data, our correlation gives a standard deviation of only 13% relative to measured values of R_{mf}. This approaches the accuracy of the basic R_m and R_{mf} measurements.

INTRODUCTION

It is necessary to know the value of the mud filtrate resistivity, R_{mf}, to be able to calculate the formation water resistivity from the S.P. log; or to calculate formation factor and/or porosity from short investigation resistivity logs; or to interpret the fluid recovery from the repeat formation tester. Due to the large effect of spurt loss, which occurs while the formation is being drilled, as compared to filtrate loss, occurring days and weeks later, as the hole is deepened, it is important to know R_{mf} as a function of time (depth). This will allow the best estimate of R_{mf} for a given formation of interest.

In the past the variation of R_{mf} with time (depth) has been inferred from log header values of R_{mf} for the several logging depths in a well. The assumption is that R_{mf} varies smoothly between logging depths. Recent work has shown the assumption above is not valid; R_{mf} and R_m vary considerably from day to day. In several wells where R_{mf} and R_m were measured daily, the standard deviation of the values estimated from the log header values relative to the daily measured values was 30% to 40%.[1,2,3]

Cause of this variation is complex, but certainly includes such factors as variation in amount and salinity of make up water additions to the mud; variations in amount of mud additives used such as bentonite, lignosulfonate, caustic soda, etc.; and contributions of dissolved salts and drilled up solids from new hole being made. Regardless of the causes, R_{mf} does vary considerably from day to day, and the log analyst must recognize this, and take it into account when interpreting the logs.

The ideal solution would be to measure R_m and R_{mf} daily, and to try to control some of the variables affecting R_{mf}, such as resistivity of the makeup water, in order to reduce the variation in R_{mf}. In practice, R_{mf} is not measured except when making a logging run; sometimes only once, or at most, a few times during the drilling of a well. Some mud logging units measure R_m (but not R_{mf}) daily. Also, the technique of "measurement while drilling" (MWD) is gaining wider use, and some of these systems measure R_m (but not R_{mf}) continuously. Mud engineers usually measure many properties of the mud daily, such as mud density, viscosity, pH, and filtrate loss, but <u>not</u> R_m or R_{mf}. A reliable method of estimating R_{mf} from R_m and mud density would be of considerable value to companies offering MWD and/or mud logging services.

Two methods have been proposed for estimating R_{mf}, given R_m. These are: Overton & Lipson's empirical correlation for non-lignosulfonate muds, $R_{mf} = C(R_m)^{1.07}$, where C is an empirical function of mud density [4,5]; and an empirical correlation given in the Schlumberger chart book, $R_{mf} = .75\ R_m$, mud type not specified. [5] Overton & Lipson's work was done in 1958, before lignosulfonate muds came into the wide use they enjoy today and no lignosulfonate muds are included in their data set.

This paper will evaluate the accuracy of R_{mf} estimates relative to measured R_{mf} values for Overton and Lipson's correlation; the $R_{mf} = .75\ R_m$ correlation; values of R_{mf} inferred from log header R_{mf} data; and a new correlation we have developed based on data given in Overton & Lipson's original paper, plus a large amount of new data we have gathered for lignosulfonate muds.

DATA AND ANALYSIS

We started our work with study of Overton & Lipson's paper. [4] It quickly became apparent that Table 1 of this paper, supposedly consisting of R_m, R_{mf} and mud density data for 94 field muds, actually contains considerable duplicated data. With a few exceptions (entries 54,67, and 71, for example), all the data for R_m, R_{mf} and mud density for entries 1 through 45 are repeated line for line for entries 46 through 94! No such duplication was noted for the data on 47 laboratory muds, given in Table 2. Five of the entries in Table 2 were incomplete, however, lacking data for R_m, mud density, or both.

We also did not understand the need for the exponent 1.07, rather than 1.0, in Overton & Lipson's correlation, $R_{mf} = C(R_m)^{1.07}$. In an empirical relation such as this it should be possible to choose slightly different values of C as a function of mud density, and use the simpler relation $R_{mf} = K_m R_m$, without significant loss of accuracy.

We began by choosing sets of Overton's data with constant mud density (mainly from their Table 2, supplemented where possible with a few points from their Table 1), and then calculated C and the R_m exponent, m', for a given constant mud density using a linear regression to fit the logarithmic form of their relation, log c = log R_{mf} - m'log R_m. The results are shown in Table 1. We see that both C and m' vary erratically. In fact, the weighted mean of m' for these 48 sets of (mostly) lab data is not 1.07 but 1.01. This encouraged us to search for a correlation including lignosulfonate muds similar to Overton's, but using an exponent of 1.0 instead of 1.07 for R_m.

Our experimental work was done both in the field and the laboratory. Mud densities were measured with a conventional Baroid mud balance; filtrate was obtained using a conventional 100 psig, lab temperature Baroid filter press; and R_m and R_{mf} measured with a Baroid Resistivity Meter (2 electrode) or a Schlumberger EMT-D meter (4 electrode). Both of the resistivity meters were calibrated using a series of NaCl solutions of varying salinity. We estimate the standard error of our resistivity measurements at 11%.

Figure 1 shows a plot of $K_m = R_{mf}/R_m$ versus mud density for Overton's non-lignosulfonate mud data. Figure 2 shows a similar plot for lignosulfonate muds used in six wells recently drilled in the Texas-Louisiana Gulf Coast area. The solid curves are "eyeball" fits to the data. Although the fitted curves are different in detail, Fig.

3, showing only the two curves superimposed, demonstrates that they actually track rather well.

Figure 4 shows the lignosulfonate data using a semilog plot of K_m versus mud density, and Fig. 5 is a similar plot which includes both the lignosulfonate and non-lignosulfonate data. A fit to the data of Fig. 5 resulted in the equation

$$\log_{10} K_m \quad = \quad \log_{10}\left(\frac{R_{mf}}{R_m}\right) \quad = \quad .396 - .0475\ \rho_m \ \ldots\ldots(1)$$

where ρ_m is mud density in pounds per gallon. This equation is plotted on both figures 4 and 5 as a solid curve, and seems a reasonable fit to both sets of data.

Table 2 gives the results of our comparison of the different commonly used methods of estimating R_{mf} from R_m. For each method, we show the % standard deviation of estimated R_{mf}, as compared to the known (measured) value of R_{mf}. We see that the results fall into three classes, regardless of mud type. The two worst methods for estimating R_{mf} are: Overton & Lipson's correlation using log header R_m data; and $R_{mf} = .75\ R_m$. These show standard deviations of about 68%. A better method is to estimate R_{mf} from log header R_{mf} values. This shows a standard deviation of 34%. The last two methods are best, namely: Overton & Lipson's original correlation using <u>measured</u> values of R_{mf} and mud density instead of log header data; and the new correlation given by equation (1) above, also using <u>measured</u> R_{mf} and mud density values. Use of equation (1) also avoids a linear interpolation from a table given in the 1985 Schlumberger Chart Book.[5] These correlations both show a standard deviation of 26%.

In only two wells were the authors directly involved in gathering the mud samples and making the measurements of R_m, R_{mf} and mud density. These were the TXO Bruce #1 well, and the Secondary Oil & Gas De Lee #1 well, both in Galveston County, Texas. For these two wells, where we are most confident of the data, the results when using our new correlation are excellent - a standard deviation of only 13% between estimated and known (measured) R_{mf} values as compared to 21% and 16% for the Overton relation using measured R_m and ρ_m data. An error of 13% approaches the accuracy of the measured R_m and R_{mf} values themselves.[6] Figures 6 & 7 show just how well the estimated and measured R_{mf} values agree for these two wells.

DISCUSSION OF RESULTS

Most of the lignosulfonate mud data we have discussed have measured R_m values between .1 and 2.0 ohm meters at 75°F. In one well however, the Republic Energy D & M Cattle Co. #1, Grimes County, Texas, nearly all the measured R_m values were greater than 2.0 ohm meters at 75°F. For this well, the correlation we have developed does not predict the measured R_{mf} values well. (See Fig. 8.) The estimated R_{mf} values track the relative changes of measured R_{mf} modestly well, but the quantitative match of estimated and measured R_{mf} is very poor, with errors approaching 100%. We don't know whether this poor result is due to bad data, or a failure of our correlation for these high R_m values. For now, we must assume the latter. Similarly, we have very little data on very saline muds. At present, we recommend use of the correlation given by equation (1) only for $.1 < R_m < 2.0$ ohm meters at 75°F. Fortunately, this includes most "fresh water" mud systems.

CONCLUSIONS

1. The exponent 1.07 is not justified in Overton and Lipson's correlation, $R_{mf} = C(R_m)^{1.07}$. Using an exponent of 1.0 with slightly different values for C works just as well and is easier to apply.

2. Both Overton & Lipson's correlation, and a new one we have developed,

$$\log_{10}\left(\frac{R_{mf}}{R_m}\right) = .396 - .0475\ \rho_m \ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

work well in all types of fresh water muds, provided that:

a) $.1 < R_m < 2.0$ ohm meters at 75°F, and

b) measured values of R_m and ρ_m are used rather than values inferred from log header data.

3. Use of the correlation $R_{mf} = .75\ R_m$ is not advisable.

4. Use of R_{mf} values estimated from log header R_{mf} data is not advisable.

5. If possible, R_m, R_{mf}, and ρ_m should be measured daily, since they vary rapidly.

6. If measurement of R_{mf} daily is not practical, R_m & ρ_m should be measured daily, and R_{mf} estimated using equation (1).

SYMBOLS

R_m = mud resistivity; ohm meters

R_{mf} = mud filtrate resistivity; ohm meters

ρ_m = mud density; pounds per gallon

K_m = R_{mf}/R_m; dimensionless

C = $R_{mf}/(R_m)^{1.07}$; (ohm meters)$^{-.07}$

ACKNOWLEDGEMENTS

Financial support from Dept. of Energy, Div. of Geothermal Energy; Gas Research Institute; and Chevron Oil Co. is gratefully acknowledged. We also thank Texas Oil & Gas Co., Chevron Oil Co., Secondary Oil & Gas Recovery, Inc., and Republic Energy Co. for supplying data used in this research.

REFERENCES

1. Williams, H. and Dunlap, H.F., 1984. "Short Term Variations in Drilling Fluid Parameters; Their Measurement and Implications". Log Analyst, Sept.-Oct., 1984; 3-9.

2. Dunlap, H.F., Dupree, Jr., J.H., and Lowe, T.A., 1985. "Effect of Makeup Water and Mud Additives on Drilling Fluid Resistivity". Proc. 6th U.S. Gulf Coast Geopressured Energy Conf., Feb., 1985 (In Press).

3. Dunlap, H.F. and Dorfman, M.H., 1981. "Problems & Partial Solutions in Using the S.P. Log to Predict Water Salinity in Deep, Hot Wells". Trans. Geo. Res. Council, Vol. 5, Oct., 1981 283-286.

4. Overton, H.L. and Lipson, L.B., 1958. "Correlation of Electrical Properties of Drilling Fluids with Solids Content". Pet. Trans. AIME, Vol. 213, 1958; 333-336.

5. Schlumberger Chart Book, Gen. 7, 1985.

6 Moore, C.V. and Kaufman, R.L., 1981. "Your Unsuspected Problems: Fluid Resistivity and Water Analysis". SPWLA Proceedings, 1981.

Mud Density (ppg)	Number of Samples (n)	C	m'
8.9	13	0.763	0.89
9.0	10	0.878	1.04
9.5	13	0.855	1.07
9.7	4	0.796	1.00
10.0	8	0.814	1.10
Weighted average of m' for all samples =			1.01

Table 1.

C and m' for several constant mud density values, Overton & Lipson (non-lignosulfonate) data.

Well Name, Number, and Location or Other Source of Data	Number of Samples (n)	Log Header R_{mf}	R_{mf}=.75R_m	Overton and Lipson's Correlation Using Log Header R_m	Overton and Lipson's Correlation Using Measured R_m	R_{mf} Calculated by equ.(1)
Chevron Jose Rodriguez #1 Cameron County, Texas	98	33%	61%	106%	23%	23%
Chevron W.S. Mootheart #1 Cameron County, Texas	71	35%	113%	36%	22%	25%
Chevron Cameron Park #1 Cameron County, Texas	63	31%	51%	33%	24%	18%
TXO Production Bruce #1 Galveston County, Texas	40	34%	31%	40%	21%	13%
Chevron State Lease 932 #32 Grand Isle Block 26, Louisiana	24	40%	40%	21%	24%	31%
Secondary Oil & Gas Inc DeLee #1	15	no openhole well logs	20%	no openhole well logs	16%	13%
Laboratory Muds Studied by Overton and Lipson (1958)	42	---	31%	---	40%	39%
Field Muds Studied by Overton and Lipson (1958)	46	---	91%	---	34%	36%
All Muds studied by Overton and Lipson (Non-Lignosulfonate)	88	---	68%	---	37%	38%
All Lignosulfonate Muds (from the six wells listed)	311	34% (n=296)	69%	67% (n=296)	23%	22%
All Muds (includes the six wells plus Overton and Lipson's data)	399	34% (n=296)	69%	67% (n=296)	26%	26%

Table II. Percent Standard Deviations for Various Methods of Estimating R_{mf}

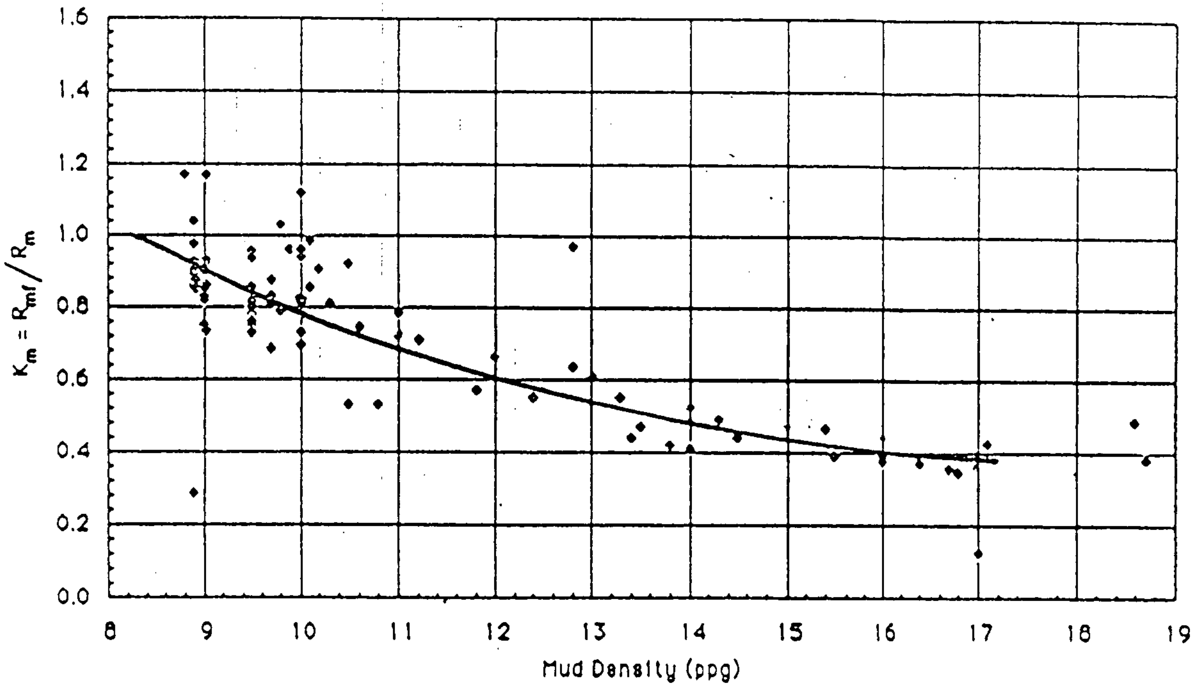


Figure 1

Km Vs Mud Density
Non Lignosulfonate Data (Overton)

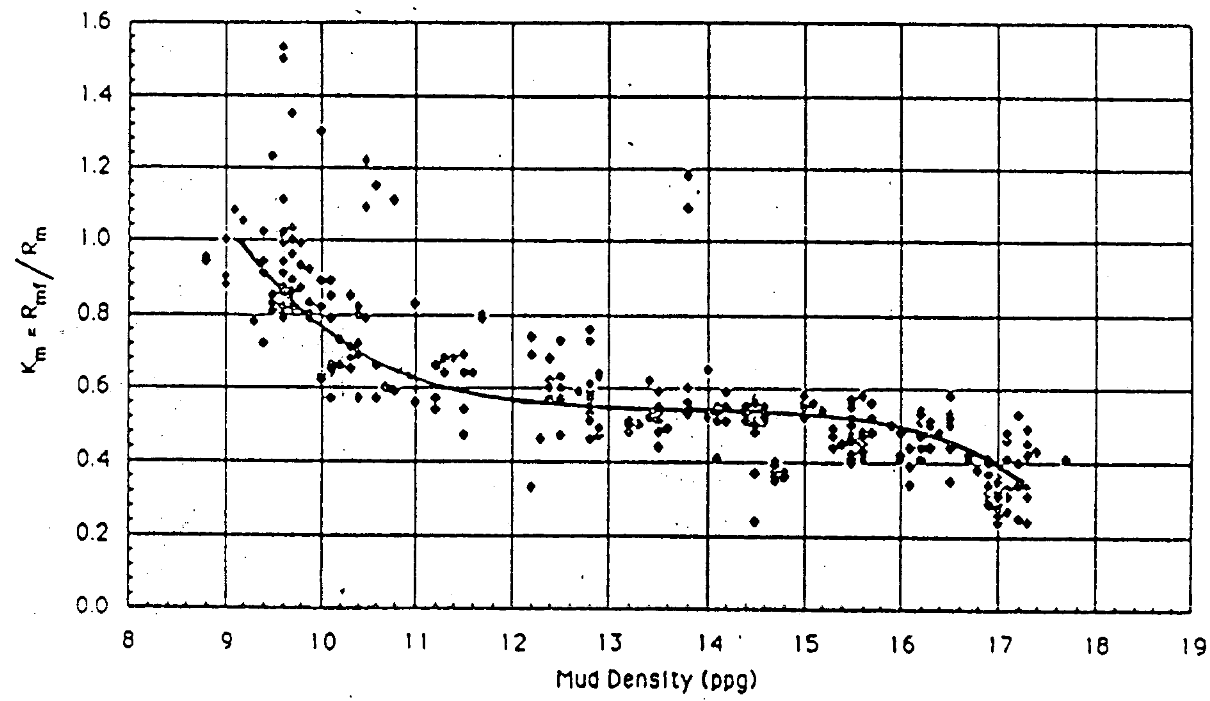


Figure 2

Km Vs Mud Density
Lignosulfonate Data (Lowe)

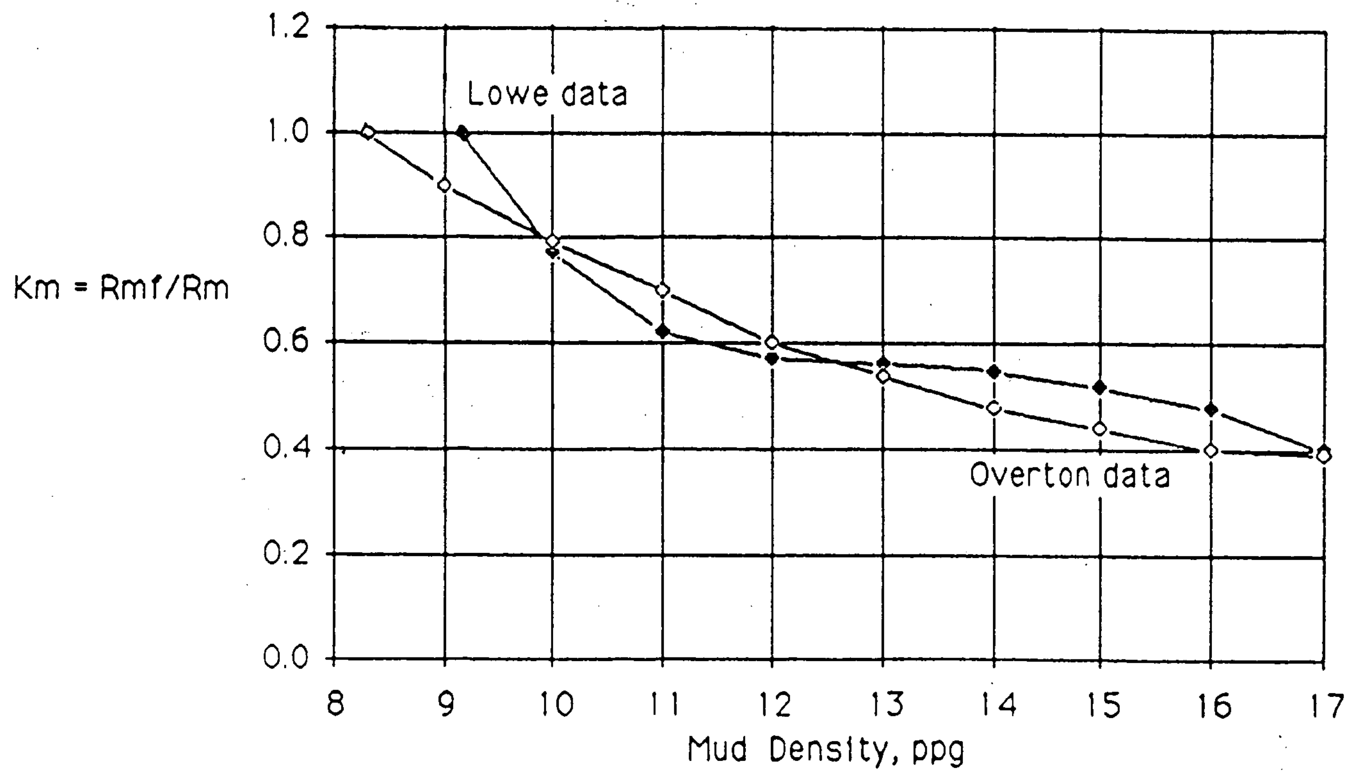


Figure 3. Km Vs Mud Density

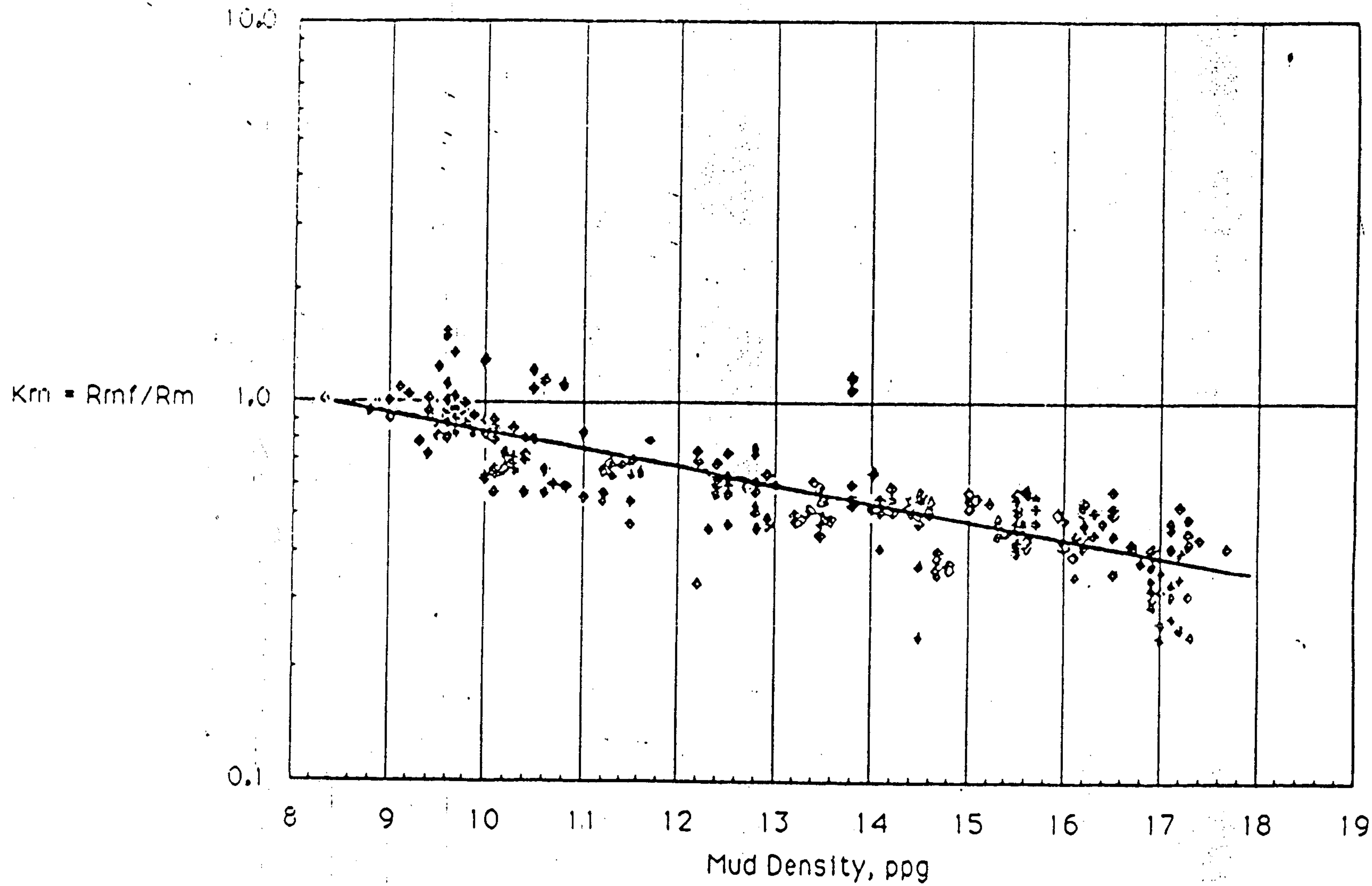


Figure 4 Km Vs Mud Density, Lignosulfonate Muds

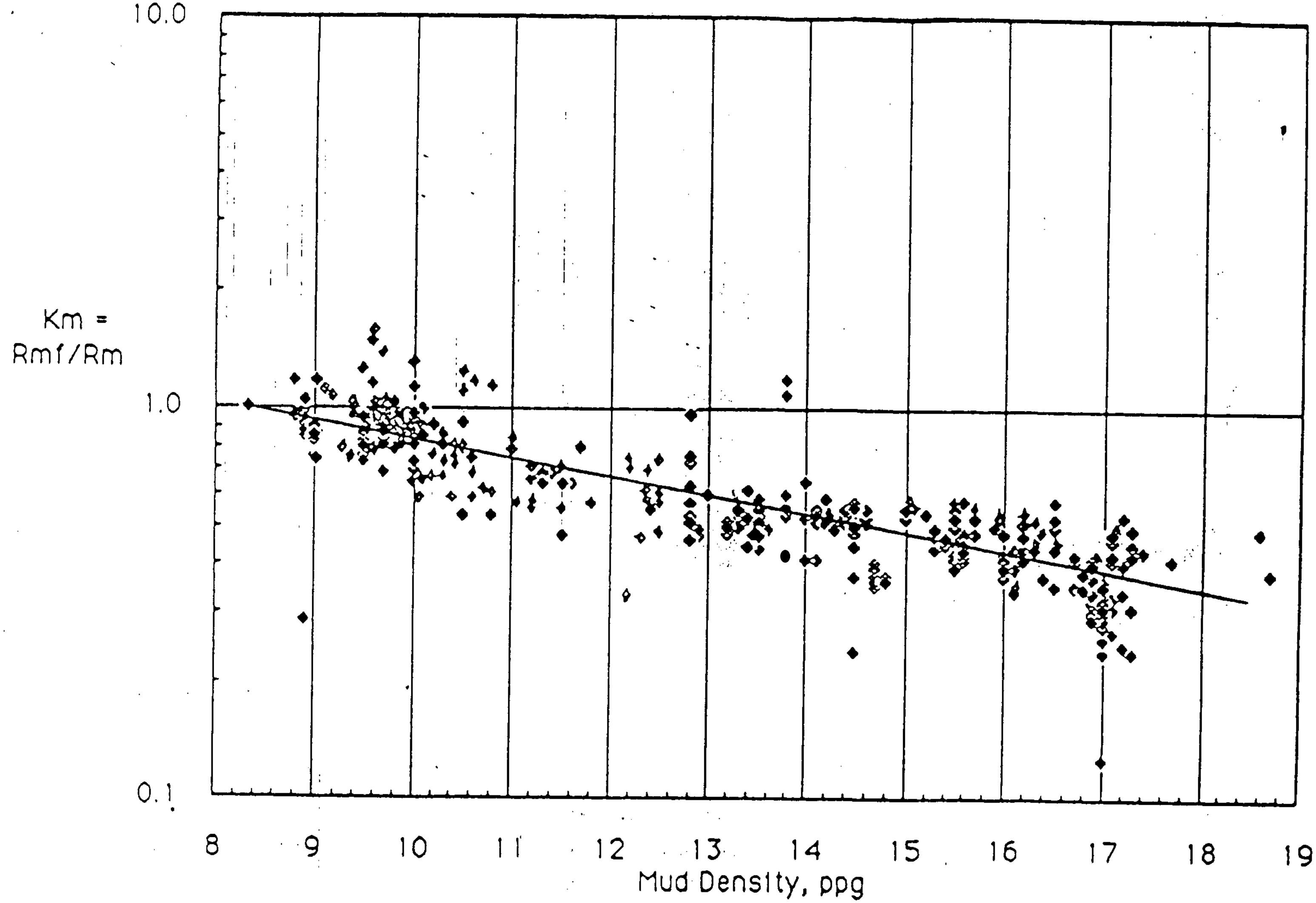


Figure 5 Km Vs Mud Density, All Muds

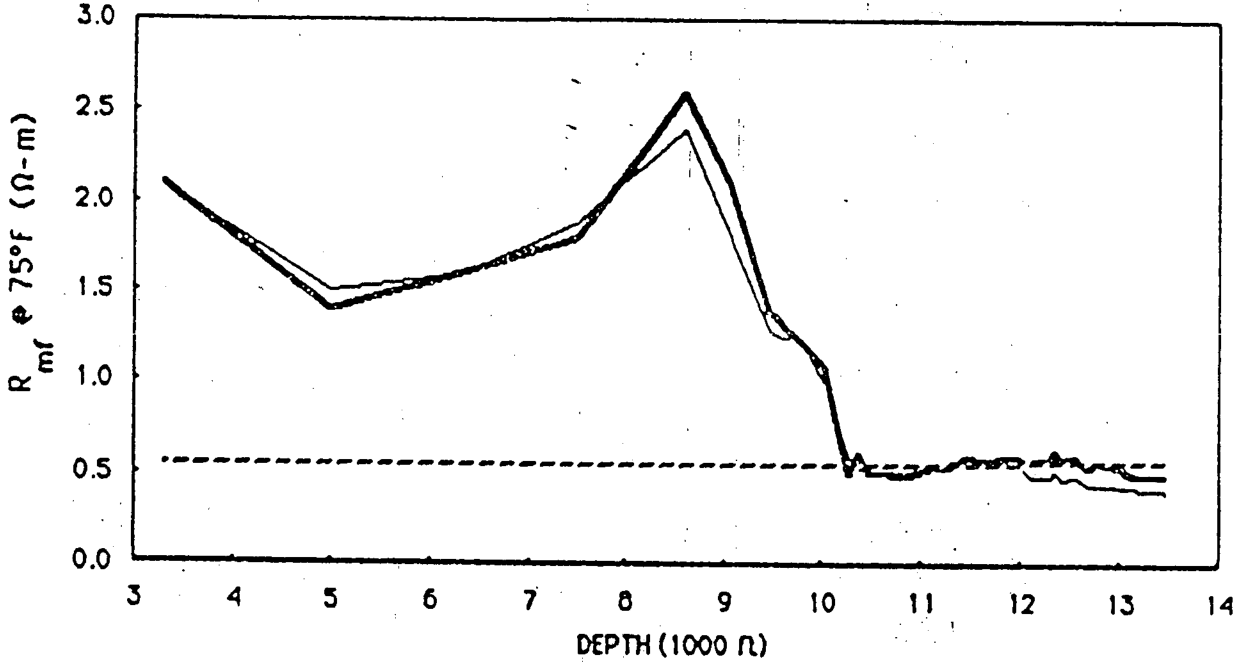


Figure 6

Rmf Vs Depth, Bruce #1 Well

Bold: Measured Rmf
Thin: Rmf from Eq. (1)
Dashed: Log header Rmf

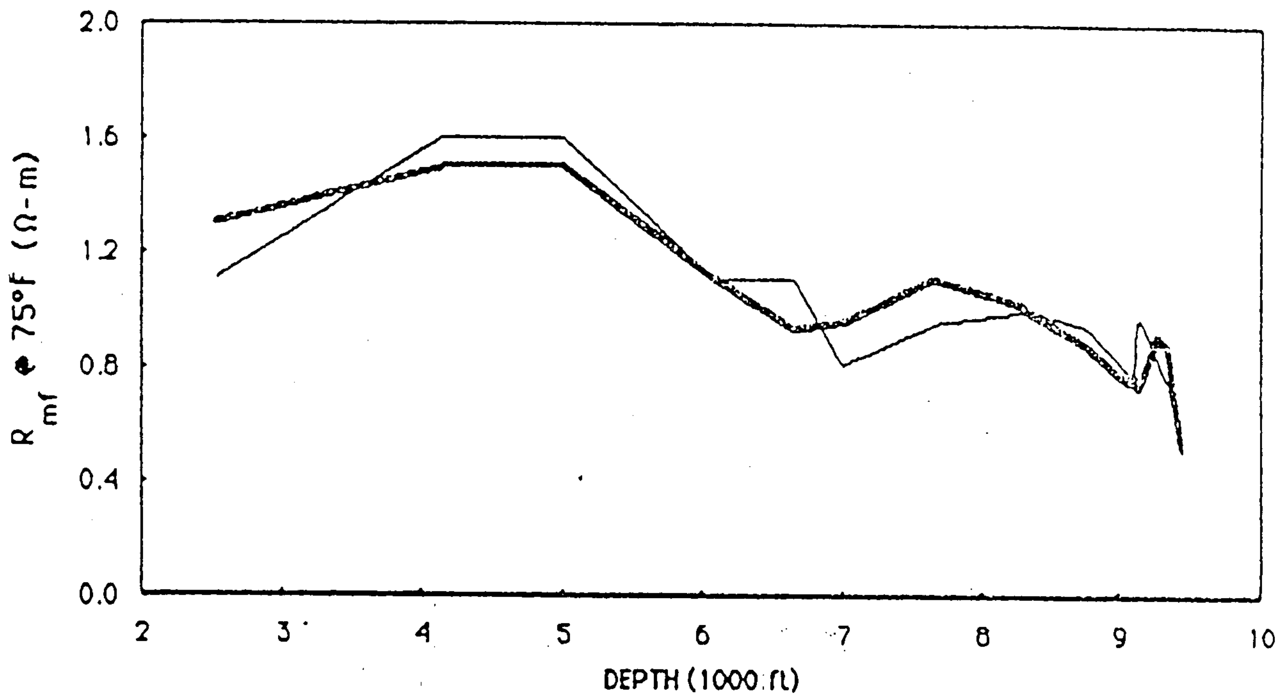


Figure 7

Rmf Vs Depth, De Lee #1 Well

Bold: Measured Rmf
Thin: RMf from Eq. (1)
No log header Rmf

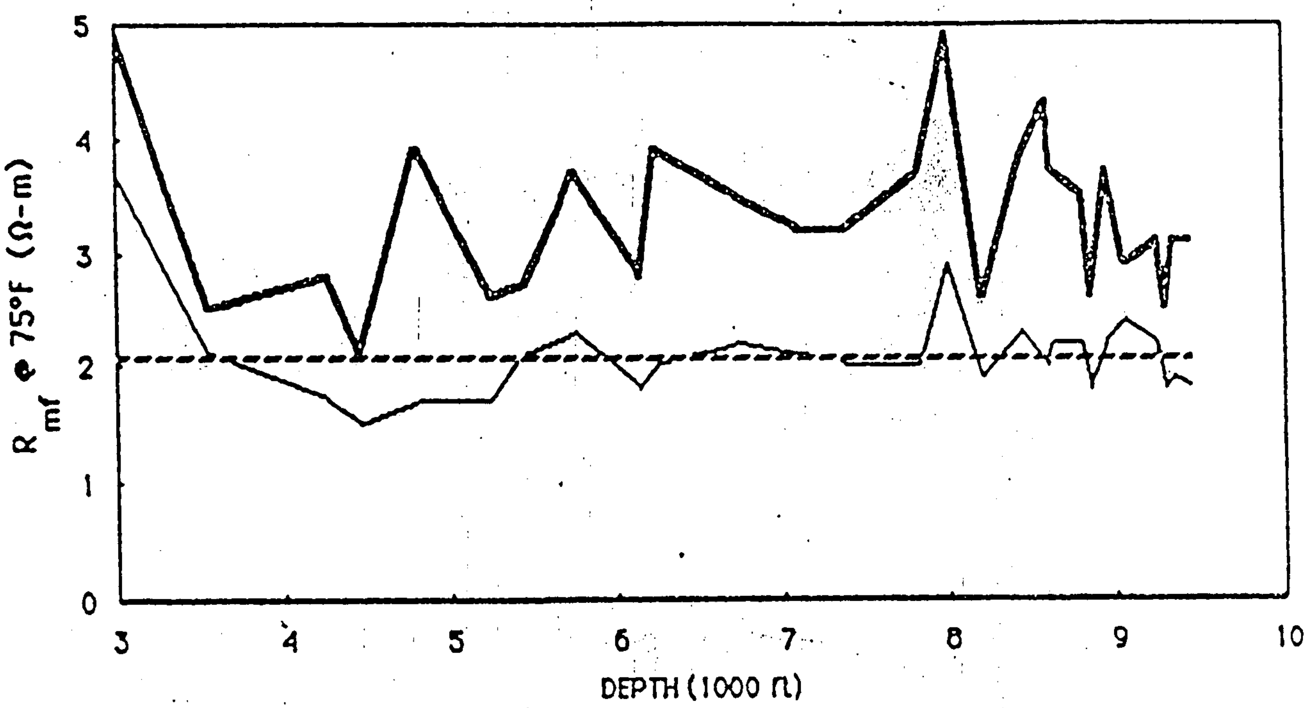


FIGURE 8

Rmf Vs Depth, D & M Cattle Co., #1

Bold: Measured Rmf
Thin: Rmf from Eq. (1)
Dashed: Log Header Rmf

About the Authors

H. F. Dunlap received his B.A. in 1938, M.A. in 1939, and Ph.D. in 1941 from Rice Institute, where he majored in physics. During World War II, he worked at the Carnegie Institution and the University of New Mexico in weapons research. From 1945 through 1975, he held various positions in the production research department of Atlantic Refining Company (now Atlantic Richfield), retiring in 1975. From 1976 to the present, he has served as Adjunct Professor in the Petroleum Engineering Department at the University of Texas at Austin.

Tom A. Lowe received his B.A. in anthropology from the University of California at San Diego in 1982, and his M.S. in Petroleum Engineering from the University of Texas at Austin, in 1985. During 1984-85, he served as President of the U.T. Student Chapter of the Society of Petroleum Engineers. This Chapter received the "Outstanding Student Chapter Award" at the SPE Convention in fall of 1985. Mr. Lowe is presently employed with Schlumberger Wireline Atlantic.

M. APPENDIX 13

COMPACTION OF GULF COAST SHALE AND SANDSTONES
SUMMARY AND DISCUSSION

K. GRAY/E. FARENTHOLD - UTA

file

BUREAU OF ENGINEERING RESEARCH
THE UNIVERSITY OF TEXAS AT AUSTIN

Center for Earth Sciences & Engineering
Balcones Research Center • 10,100 Burnet Rd. • Austin, Texas 78758 • (512)471-7190

March 18, 1986

H. F. Coffer
EG&G Chandler Engineering
7707 E. 38th St.
Tulsa, OK 74145

Dear Hank:

Enclosed is a summary of my presentation at the Geopressured Industry Forum in Houston on March 5, 1986, and copies of the transparencies used to support that presentation.

If you need any additional information, please let me know.

Sincerely,

E. P. Fahrenthold

E. P. FAHRENTHOLD
Assistant Professor

EPF/rs

encl

Research Activities Summary
"Compaction of Gulf Coast Shale and Sandstone"

Geopressured Industry Forum
Houston, Texas
March 5, 1986

by

E. P. Fahrenthold and K. E. Gray

Compaction testing on geopressured-geothermal reservoir rock has included uniaxial and triaxial tests on sandstone and shale (Slide #1). The uniaxial tests simulate one-dimensional reservoir compaction with pore pressure drawdown, while the triaxial tests provide an independent measure of mechanical rock properties, in this case under constant pore pressure conditions (Slide #2).

Modelling of these tests has taken two forms (Slide #3). Polynomial interpolation of the stress-strain curves provides incremental values of the loading and unloading moduli. Secondly, a nonlinear compaction model of the rock behavior has been formulated and was distributed in the December 1985 progress report. This work is scheduled for publication in the Journal of Energy Resources Technology, ASME, in June, 1986. More recent work will be reported in a paper to be presented at the 27th U. S. Symposium on Rock Mechanics in June, 1986.

Additional testing equipment has been obtained or requested to enhance the experimental facilities employed in the conduct of these tests (Slide #4). Shale swelling equipment has been donated from industry resources to the Center for Earth Sciences and Engineering. In addition, an equipment proposal for a rock testing system has been prepared and submitted to the Department of Energy University Research Instrumentation Program.

The material which follows presents results of compaction tests on shale and sandstone, and loading/unloading moduli calculated from these laboratory tests (Slides #5-19).

COMPACTION OF GULF COAST SHALE AND SANDSTONE

E. P. Fahrenthold
Department of Mechanical Engineering

K. E. Gray
Department of Petroleum Engineering

The University of Texas at Austin

<u>COMPACTION TESTING</u>

TRIAXIAL
Constant Confining Pressure and Pore Pressure,
Variable Axial Total Stress

UNIAXIAL
Constant Axial Total Stress and Radial Strain,
Variable Pore Pressure

MODELLING

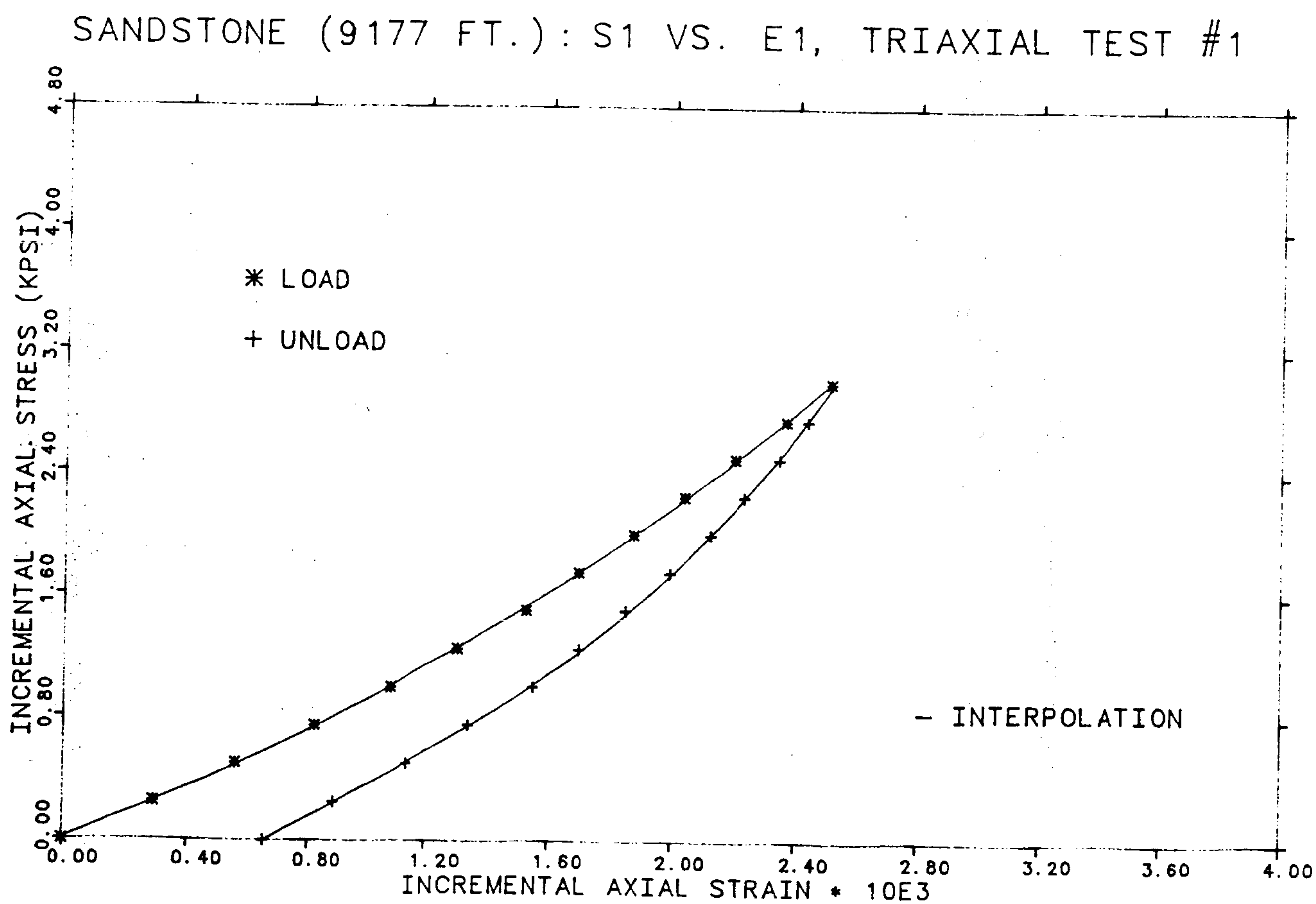
Polynomial Interpolation
(Used to Calculate Incremental Values for Young's
Modulus and Poisson's Ratio)

Nonlinear Compaction Model
(Progress Report, December 1985)

EQUIPMENT ACQUISITION

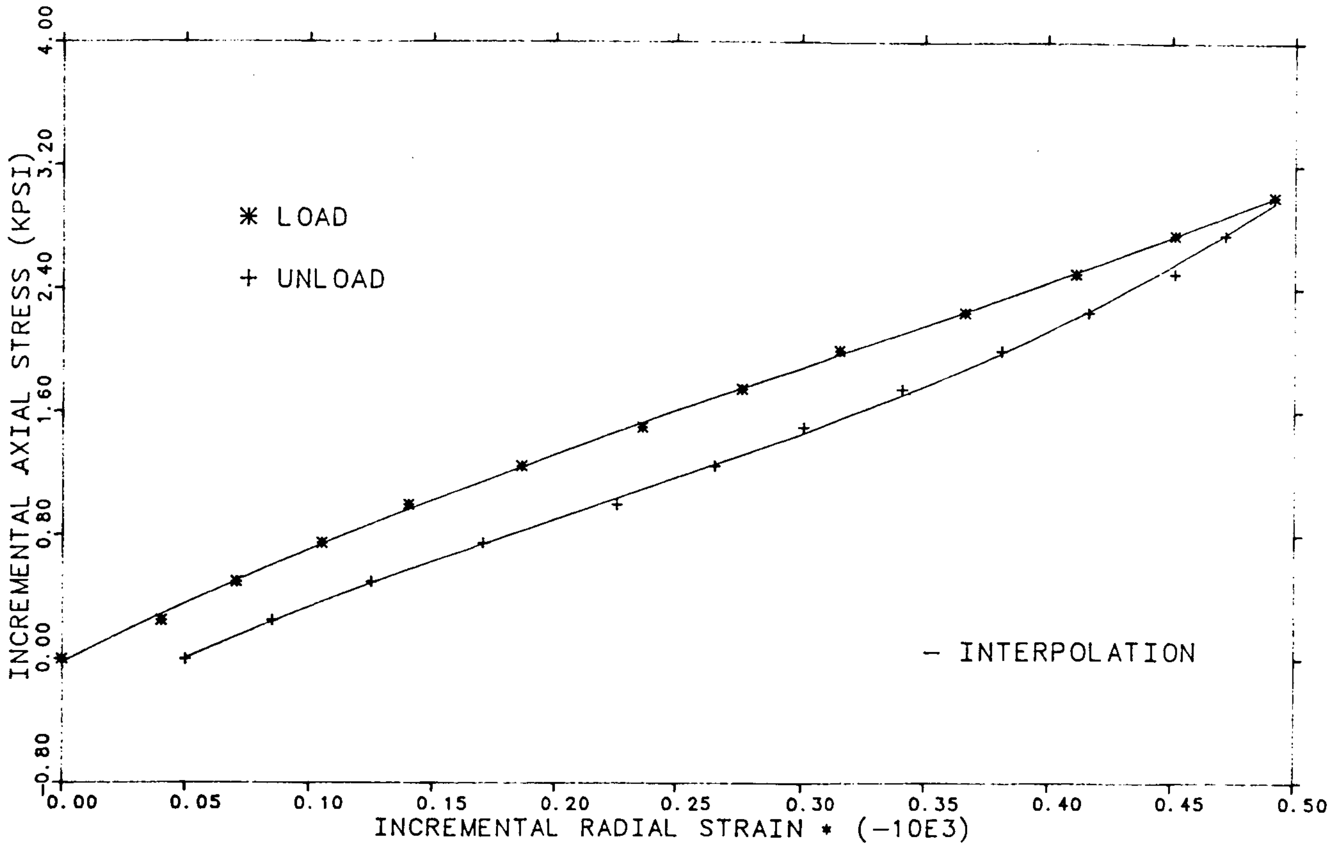
Shale Swelling and Related Equipment
Donations from Industry

DOE University Research Instrumentation Program
(Proposal Submitted in December 1985)

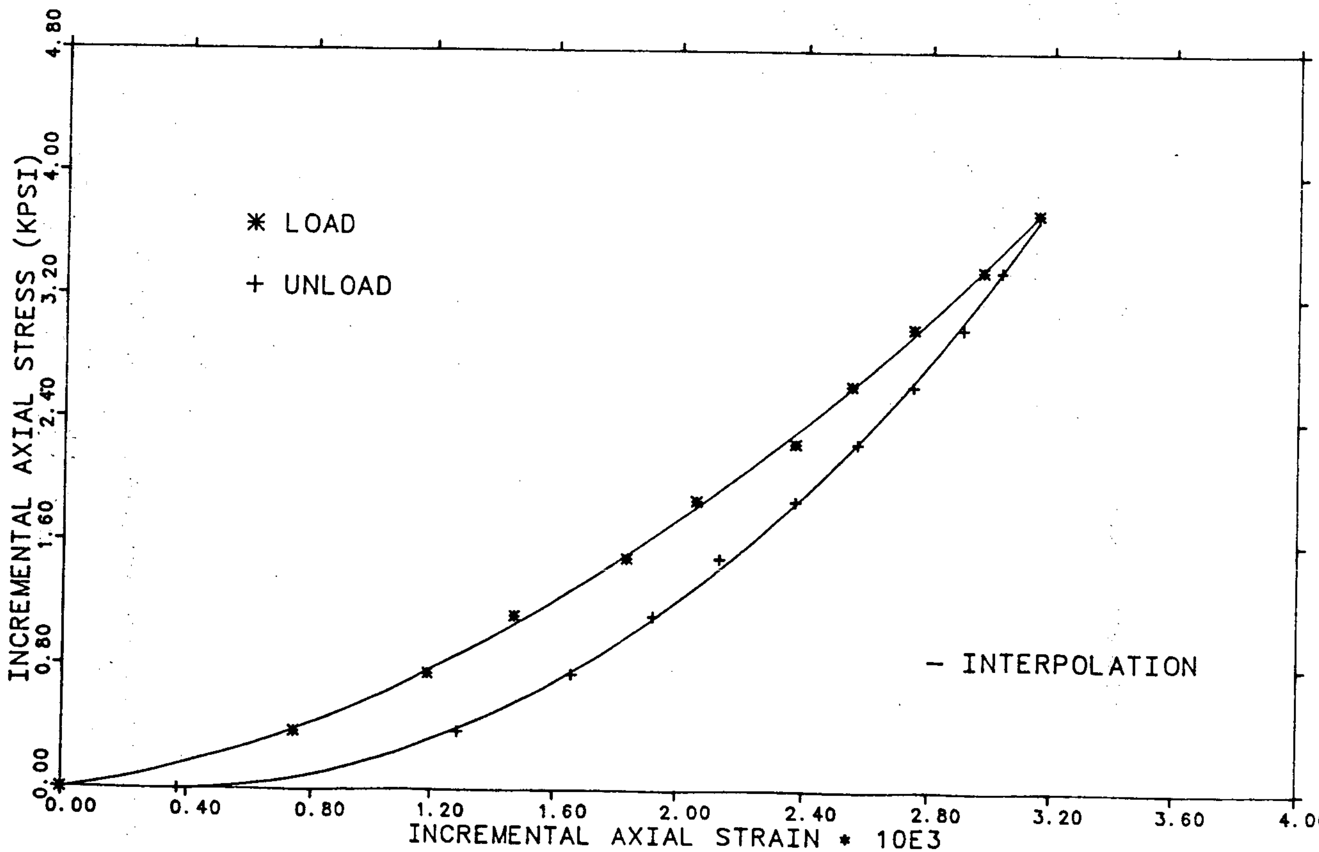


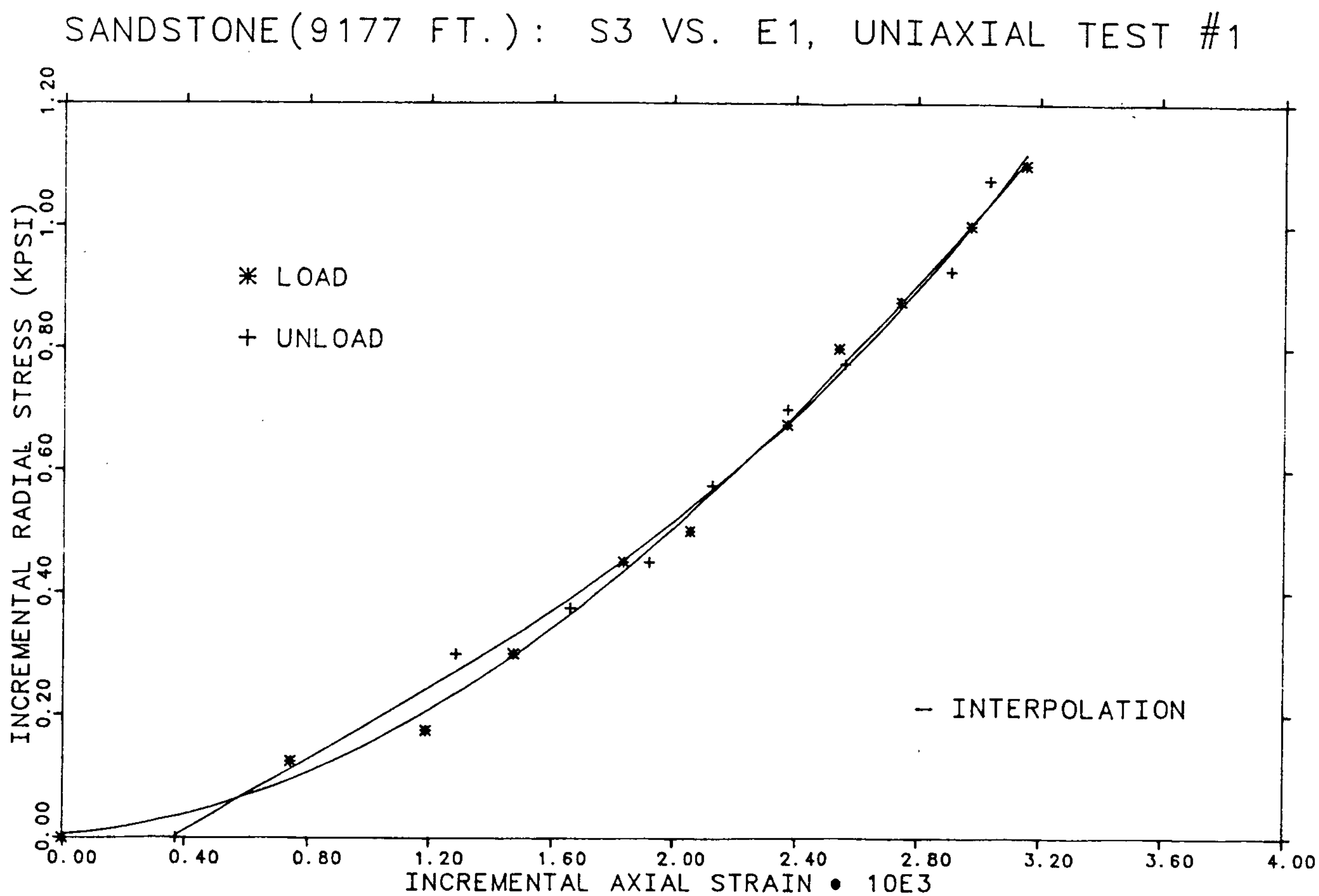
SANDSTONE (9177 FT.): S1 VS. E1, TRIAXIAL TEST #1
INCREMENTAL AXIAL STRESS (KPSI)
INCREMENTAL AXIAL STRAIN * 10E3
* LOAD
+ UNLOAD
— INTERPOLATION
0.00
0.40
0.80
1.20
1.60
2.00
2.40
2.80
3.20
3.60
4.00
4.80

SANDSTONE (9177 FT.): S1 VS. E3, TRIAXIAL TEST #1



SANDSTONE(9177 FT.): S1 VS. E1, UNIAXIAL TEST #1





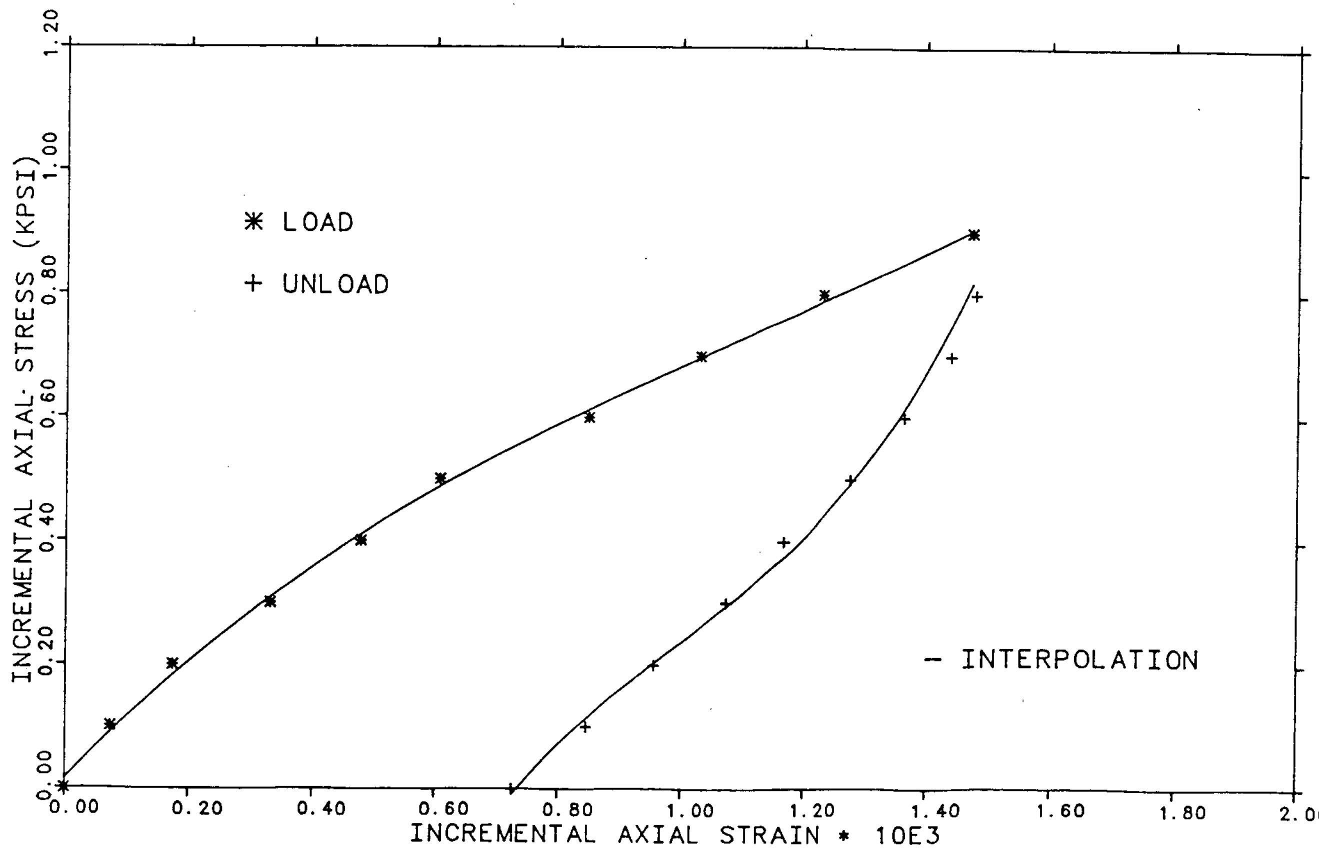
SANDSTONE(9177 FT.): S3 VS. E1, UNIAXIAL TEST #1
INCREMENTAL RADIAL STRESS (KPSI)
0.00
0.20
0.40
0.60
0.80
1.00
1.20
INCREMENTAL AXIAL STRAIN • 10E3
0.00
0.40
0.80
1.20
1.60
2.00
2.40
2.80
3.20
3.60
4.00
LOAD
UNLOAD
INTERPOLATION

SANDSTONE(9177 FT.): UNIAXIAL TEST #1

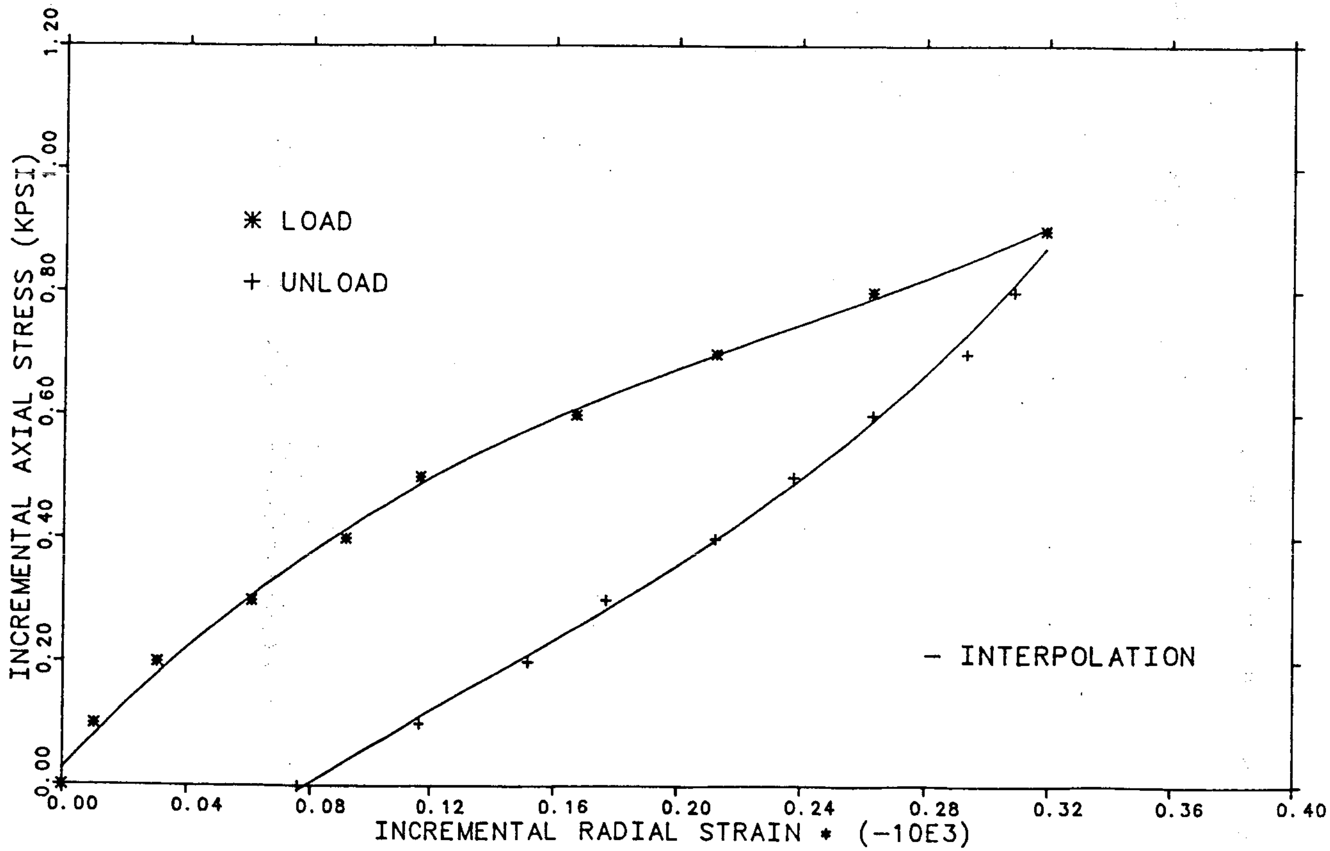
AXIAL TOTAL STRESS = 4500 PSI.

EZ (*10E3)	ER (*10E3)	P (KPSI)	TR (KPSI)	CM (MPSI)	NU –
		- LOADING -			
1.04	.65	3.88	4.10	.74	.22
1.49	.65	3.50	3.78	.99	.23
1.77	.66	3.13	3.53	1.14	.23
2.14	.65	2.75	3.30	1.34	.24
2.36	.66	2.38	2.97	1.46	.24
2.67	.66	2.00	2.78	1.63	.23
2.85	.66	1.63	2.53	1.72	.23
3.05	.66	1.25	2.22	1.82	.23
3.27	.66	.88	1.97	1.94	.23
3.45	.66	.50	1.70	2.03	.23
		- UNLOADING -			
3.45	.66	.50	1.70	2.84	.19
3.33	.66	.88	2.05	2.69	.19
3.21	.66	1.25	2.28	2.54	.19
3.05	.66	1.63	2.60	2.34	.19
2.87	.65	2.00	2.88	2.14	.19
2.67	.66	2.38	3.18	1.92	.20
2.44	.66	2.75	3.43	1.66	.20
2.22	.66	3.13	3.68	1.44	.21
1.96	.66	3.50	3.97	1.17	.23
1.59	.66	3.88	4.28	.83	.27

SHALE (9067 FT.): S1 VS. E1, TRIAXIAL TEST #1



SHALE (9067 FT.): S1 VS. E3, TRIAXIAL TEST #1

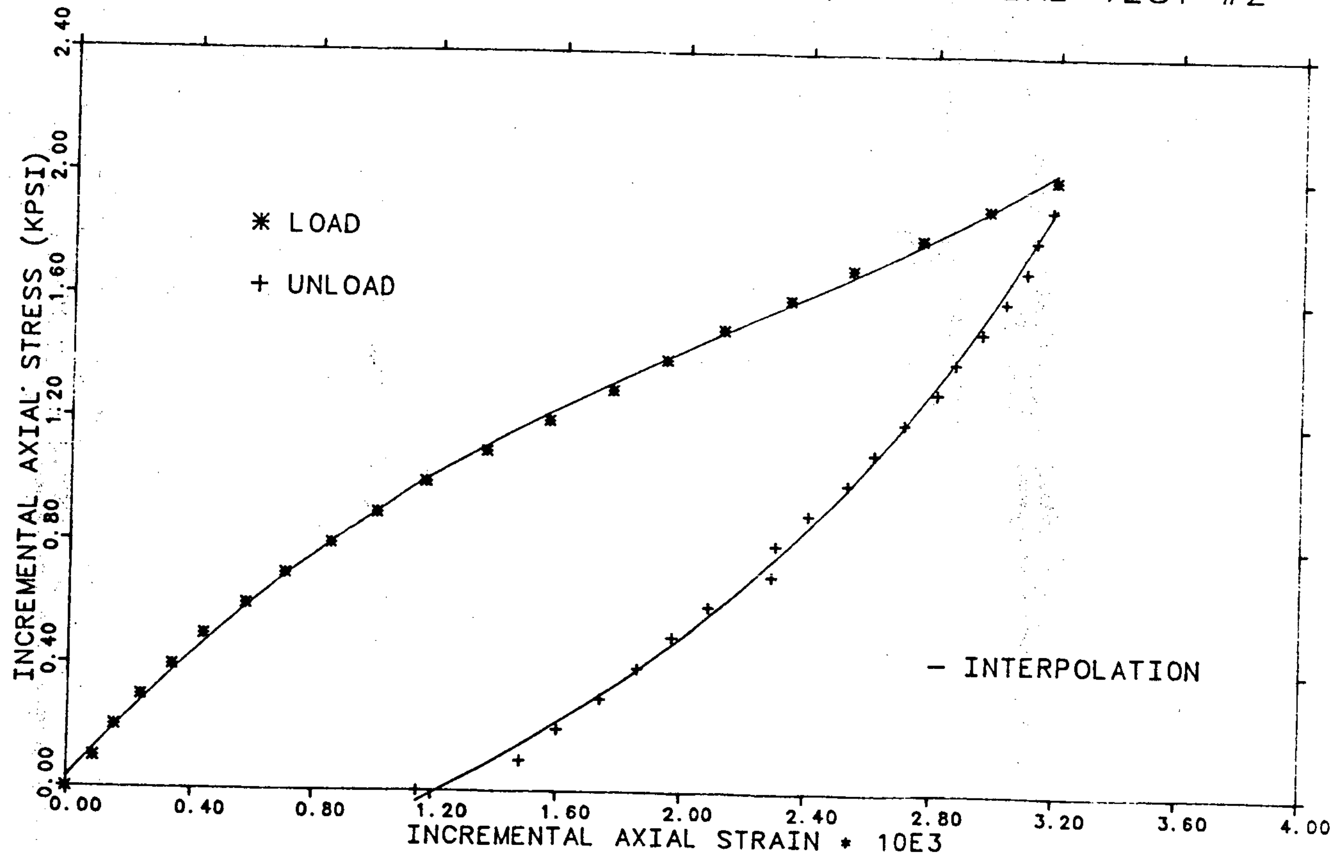


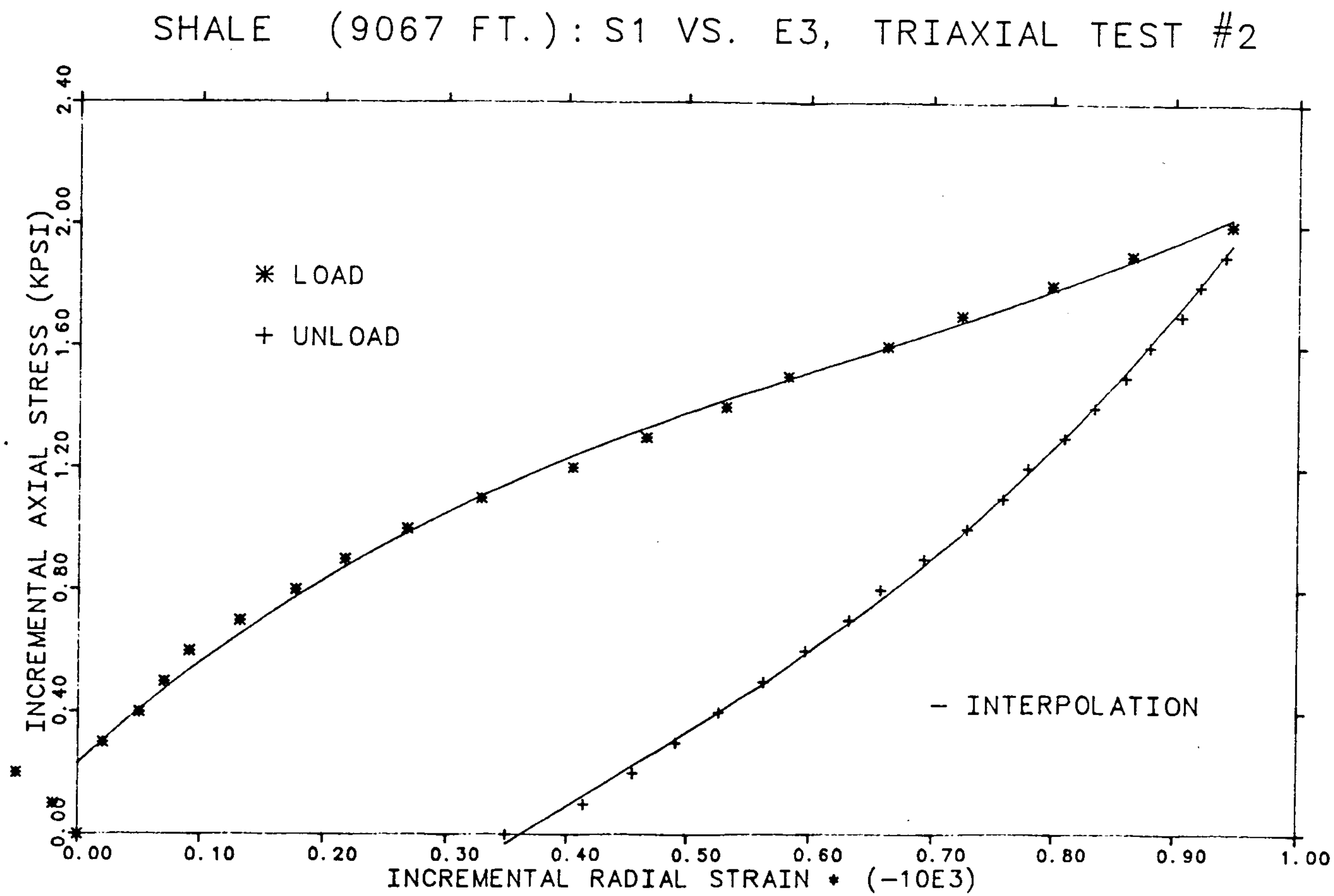
H. SHALE (9067 FT.): TRIAXIAL TEST #1

PORE PRESSURE = 14.7 PSI.

EZ (*10E3)	ER (*10E3)	TZ (KPSI)	TR (KPSI)	E (MPSI)	NU -
		- LOADING -			
6.34	4.84	4.20	4.00	.97	.19
6.44	4.86	4.30	4.00	.87	.19
6.60	4.89	4.40	4.00	.74	.19
6.75	4.92	4.50	4.00	.64	.20
6.88	4.95	4.60	4.00	.57	.21
7.12	5.00	4.70	4.00	.48	.23
7.30	5.05	4.80	4.00	.45	.25
7.50	5.10	4.90	4.00	.46	.25
7.74	5.15	5.00	4.00	.52	.23
		- UNLOADING -			
7.74	5.15	5.00	4.00	2.17	.37
7.75	5.14	4.90	4.00	2.21	.40
7.71	5.13	4.80	4.00	1.98	.39
7.63	5.10	4.70	4.00	1.60	.37
7.55	5.07	4.60	4.00	1.26	.33
7.44	5.05	4.50	4.00	.94	.28
7.35	5.01	4.40	4.00	.79	.26
7.23	4.98	4.30	4.00	.76	.27
7.11	4.95	4.20	4.00	.89	.32

SHALE (9067 FT.): S1 VS. E1, TRIAXIAL TEST #2

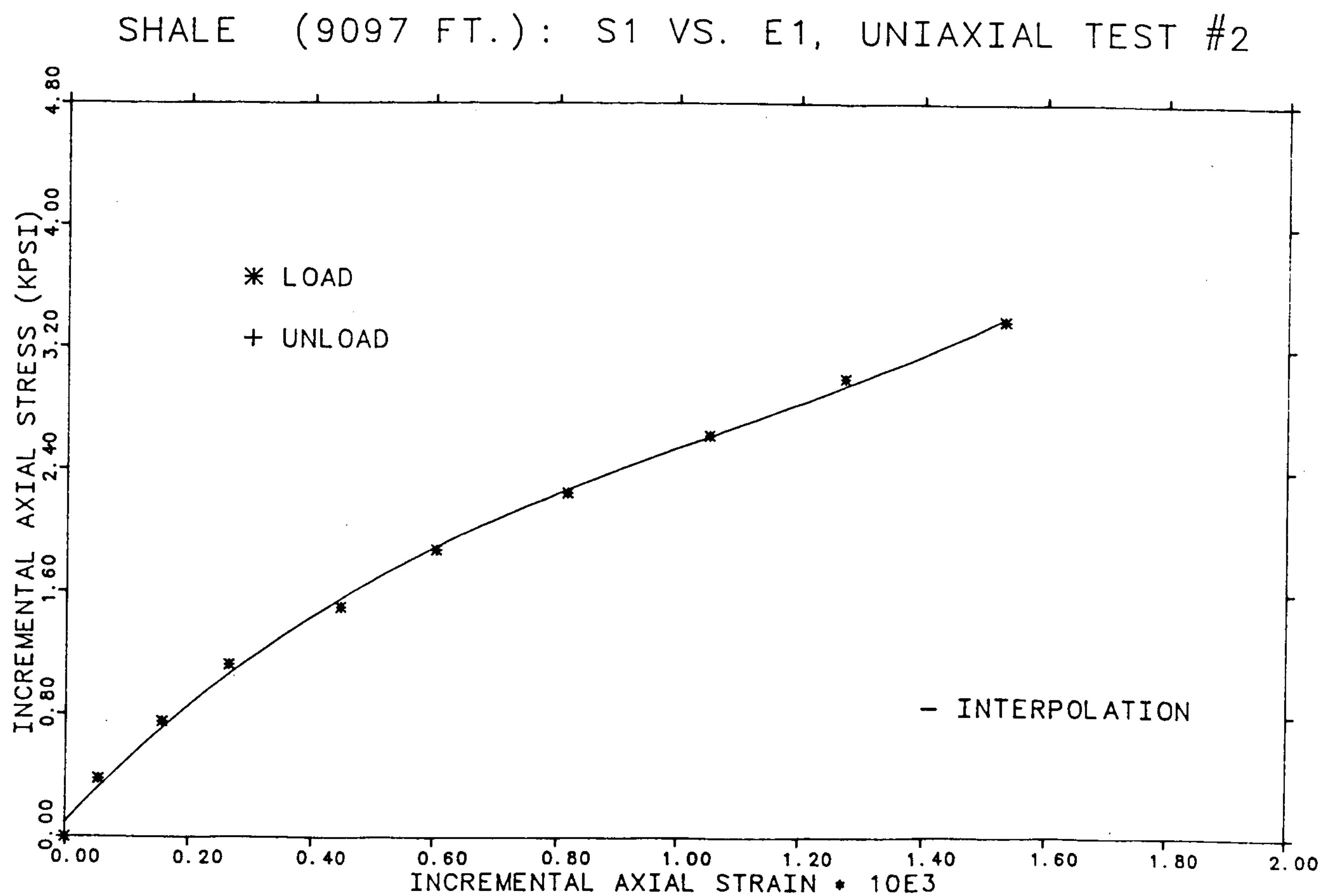



SHALE (9067 FT.): S1 VS. E3, TRIAXIAL TEST #2
INCREMENTAL AXIAL STRESS (KPSI)
INCREMENTAL RADIAL STRAIN * (-10E3)
0.00
0.40
0.80
1.20
1.60
2.00
2.40
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00
LOAD
UNLOAD
- INTERPOLATION

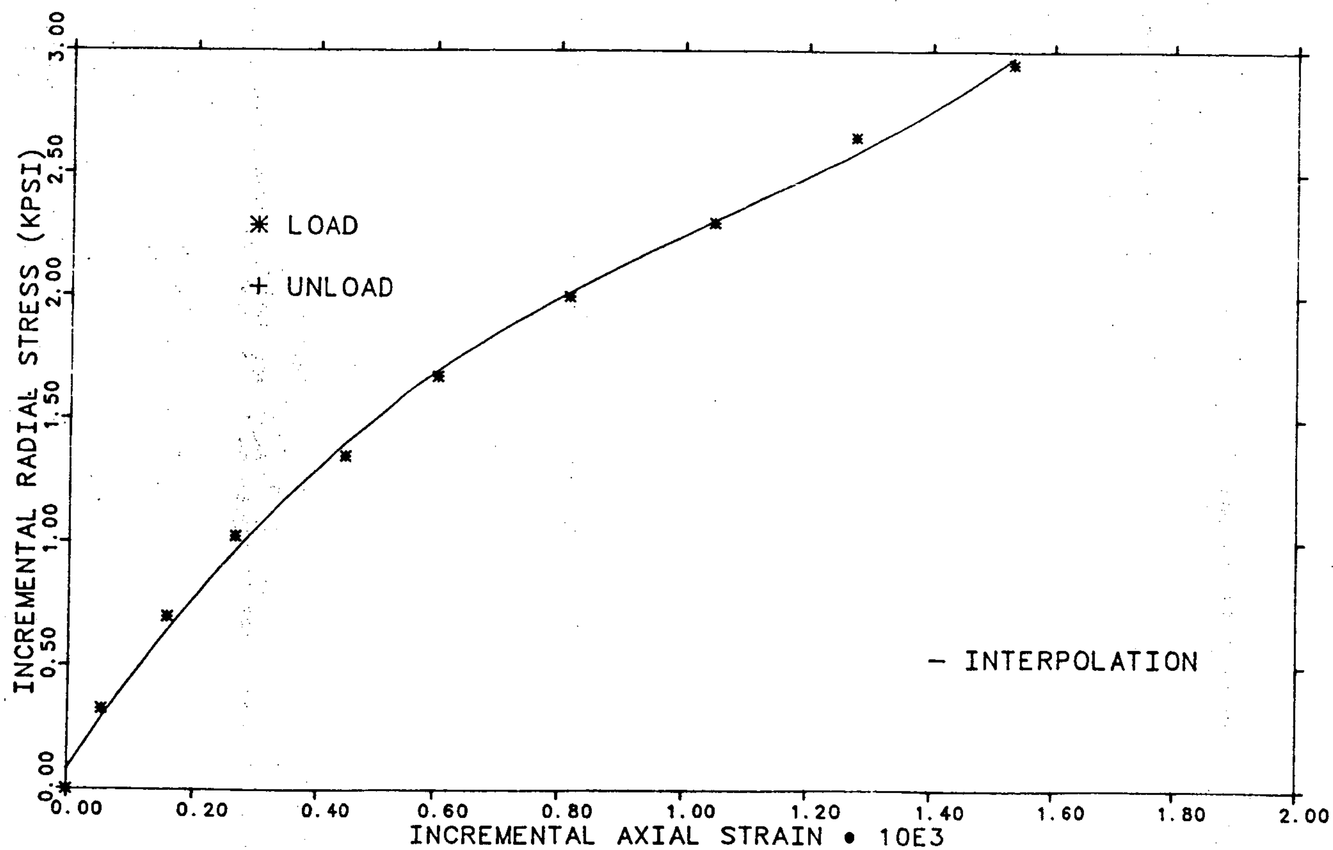
H. SHALE (9067 FT.): TRIAXIAL TEST #2

PORE PRESSURE = 14.7 PSI.

EZ (*10E3)	ER (*10E3)	TZ (KPSI)	TR (KPSI)	E (MPSI)	NU -
		- LOADING -			
7.16	4.79	3.10	3.00	1.09	.28
7.23	4.76	3.20	3.00	1.05	.26
7.31	4.83	3.30	3.00	1.00	.28
7.41	4.86	3.40	3.00	.94	.29
7.52	4.88	3.50	3.00	.89	.28
7.65	4.90	3.60	3.00	.82	.27
7.78	4.94	3.70	3.00	.77	.27
7.93	4.98	3.80	3.00	.71	.28
8.08	5.03	3.90	3.00	.65	.28
8.25	5.08	4.00	3.00	.60	.29
8.44	5.14	4.10	3.00	.55	.29
8.64	5.21	4.20	3.00	.50	.31
8.85	5.27	4.30	3.00	.47	.32
9.02	5.34	4.40	3.00	.46	.34
9.21	5.39	4.50	3.00	.45	.34
9.42	5.47	4.60	3.00	.46	.35
9.62	5.53	4.70	3.00	.47	.35
9.84	5.61	4.80	3.00	.50	.35
10.05	5.67	4.90	3.00	.55	.34
10.28	5.75	5.00	3.00	.61	.33
		- UNLOADING -			
10.28	5.75	5.00	3.00	1.71	.32
10.26	5.75	4.90	3.00	1.70	.32
10.21	5.73	4.80	3.00	1.64	.33
10.18	5.71	4.70	3.00	1.61	.33
10.11	5.69	4.60	3.00	1.54	.33
10.04	5.67	4.50	3.00	1.46	.33
9.95	5.64	4.40	3.00	1.38	.33
9.89	5.62	4.30	3.00	1.33	.33
9.79	5.59	4.20	3.00	1.24	.33
9.69	5.57	4.10	3.00	1.16	.32
9.61	5.54	4.00	3.00	1.10	.32
9.49	5.50	3.90	3.00	1.01	.31
9.39	5.47	3.80	3.00	.94	.31
9.37	5.44	3.70	3.00	.94	.32
9.17	5.40	3.60	3.00	.82	.29
9.05	5.37	3.50	3.00	.76	.28
8.94	5.33	3.40	3.00	.71	.28
8.82	5.30	3.30	3.00	.66	.27
8.68	5.26	3.20	3.00	.62	.25


SHALE (9097 FT.): S1 VS. E1, UNIAXIAL TEST #2
INCREMENTAL AXIAL STRESS (KPSI)
INCREMENTAL AXIAL STRAIN * 10E3
* LOAD
+ UNLOAD
— INTERPOLATION
0.00
0.80
1.60
2.40
3.20
4.00
4.80
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00

SHALE (9097 FT.): S3 VS. E1, UNIAXIAL TEST #2



H. SHALE (9097 FT.): UNIAXIAL TEST #2

AXIAL TOTAL STRESS = 4500 PSI.

EZ (*10E3)	ER (*10E3)	P (KPSI)	TR (KPSI)	CM (MPSI)	NU -
1.38	.48	3.50	4.30	4.05	.48
1.49	.48	3.13	4.30	3.53	.48
1.60	.48	2.75	4.25	3.06	.47
1.78	.47	2.38	4.20	2.41	.47
1.93	.48	2.00	4.15	1.97	.46
2.15	.48	1.63	4.10	1.59	.46
2.38	.48	1.25	4.03	1.43	.45
2.61	.48	.88	4.00	1.55	.46
2.86	.48	.50	3.93	2.00	.47

H. SHALE (9097 FT.): UNIAXIAL TEST #1

AXIAL TOTAL STRESS = 4500 PSI.

EZ (*10E3)	ER (*10E3)	P (KPSI)	TR (KPSI)	CM (MPSI)	NU -
3.05	.49	3.50	4.30	1.48	.44
3.22	.49	3.13	4.25	1.40	.44
3.65	.49	2.75	4.15	1.31	.46
4.02	.49	2.38	4.05	1.40	.47
4.29	.49	2.00	4.05	1.55	.48
4.39	.49	1.63	4.03	1.63	.48
4.55	.49	1.25	4.00	1.78	.48
4.77	.49	.88	3.97	2.02	.49
5.04	.49	.50	3.95	2.40	.49

N. APPENDIX 14

REVIEW OF GRI PROGRAMS

LEO ROGERS - GRI

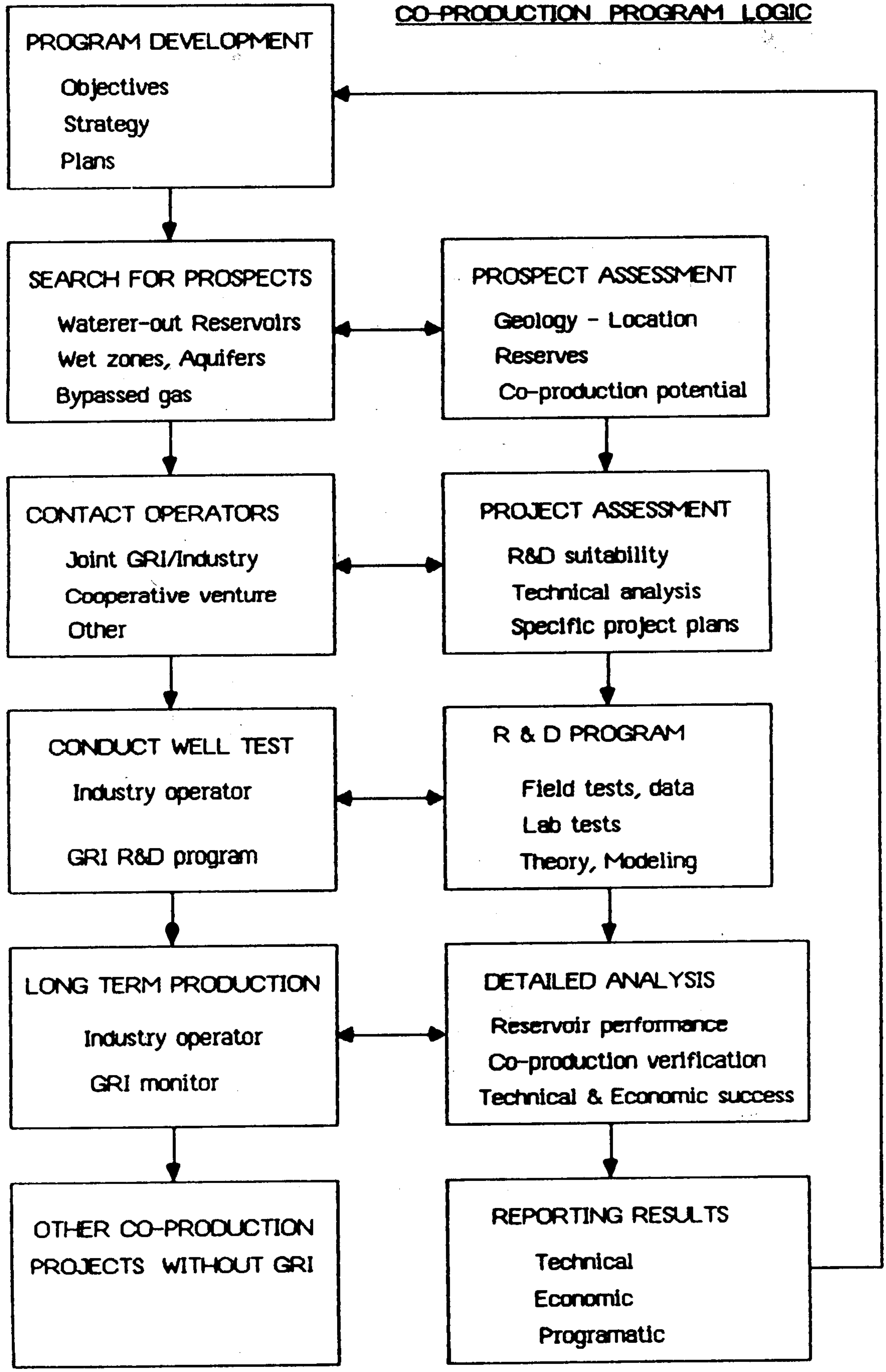
BROAD CO-PRODUCTION PROGRAM GOALS

- Prove Postulated Co-Production Techniques to Be Technically and Economically Viable
- Remove Technical and Economic Uncertainties that Inhibit Development of the Resource
- Identify Any Environmental Issues and Ways to Solve Problems or Concerns

FOCUSED CO-PRODUCTION PROGRAM GOALS

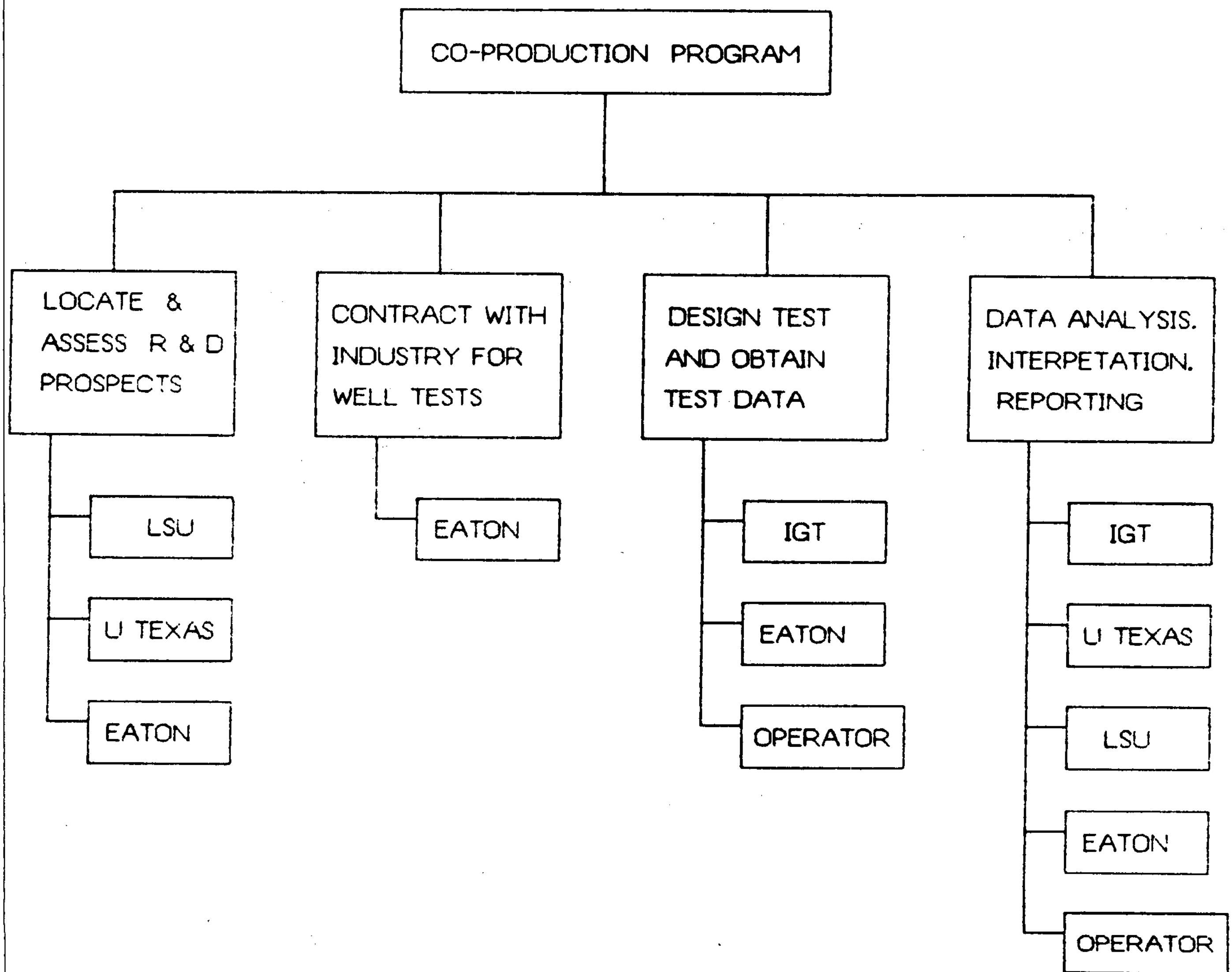
- Development of Technically Efficient and Cost Effective Ways to Process and Dispose of Brine
- Develop Ways to Forecast When Scaling will Occur and How it Can Be Prevented or Controlled
- Develop Ways to Evaluate Co-Production Well Performance and to Project Deliverability and Reserves
- Develop Technical Data Base on Gas/Brine Systems and Properties of Water Saturated Reservoir Rock Needed for Understanding of Co-Production

CO-PRODUCTION PROGRAM LOGIC



WORK BREAKDOWN STRUCTURE

(FIRST LEVEL)



Flow Diagram for Co-Production of Gas and Water Project Area (1.1.3)

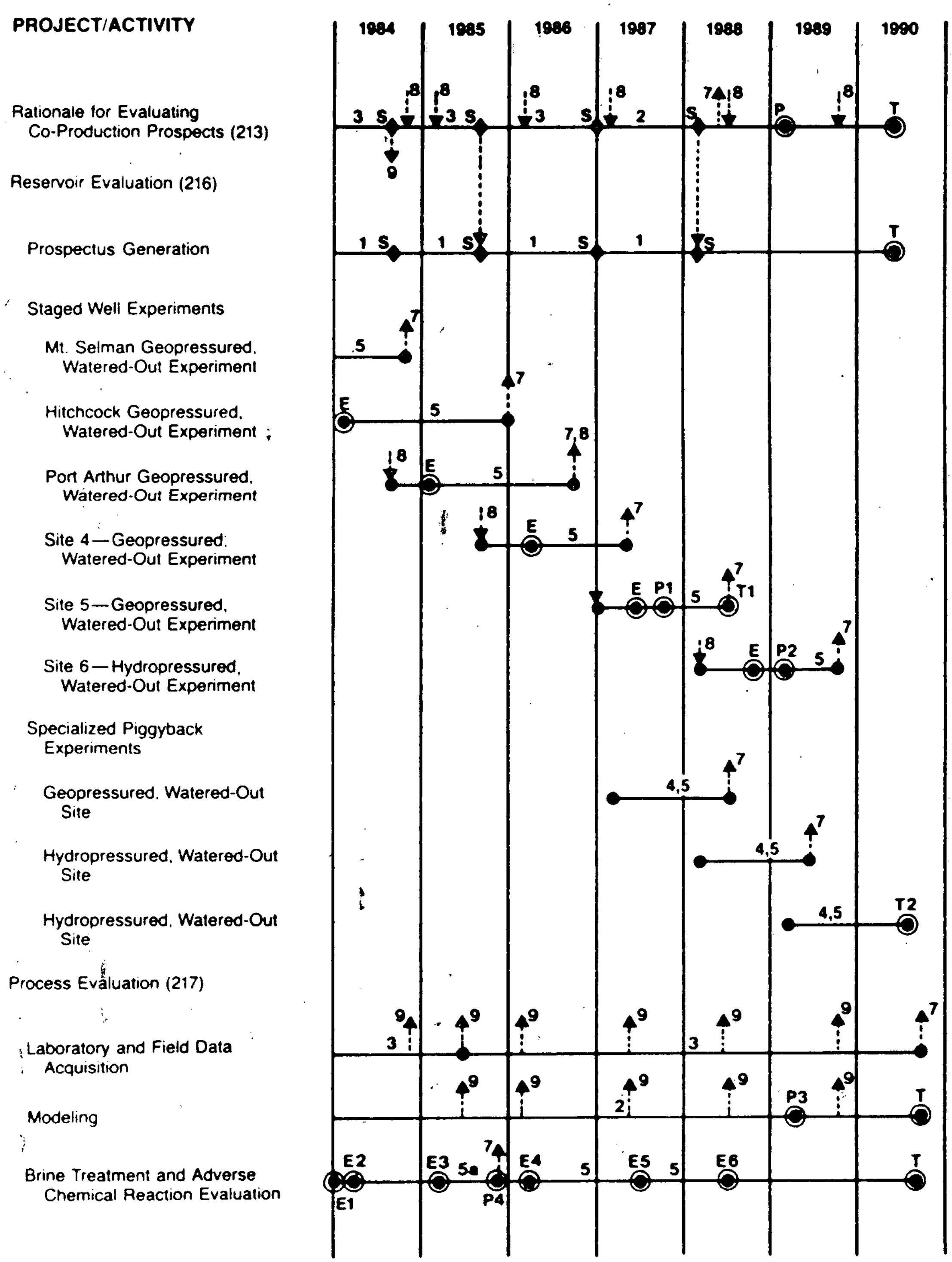
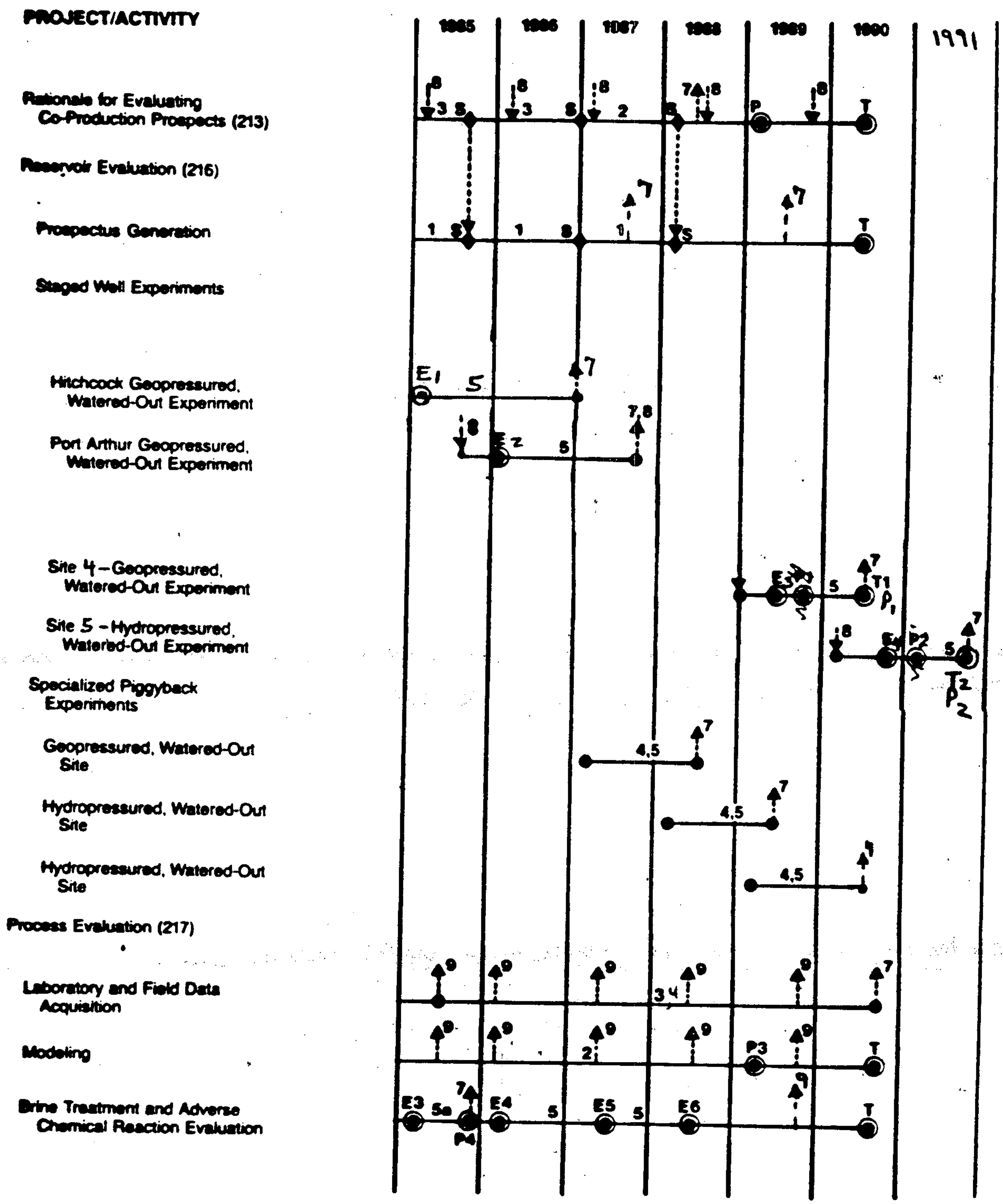
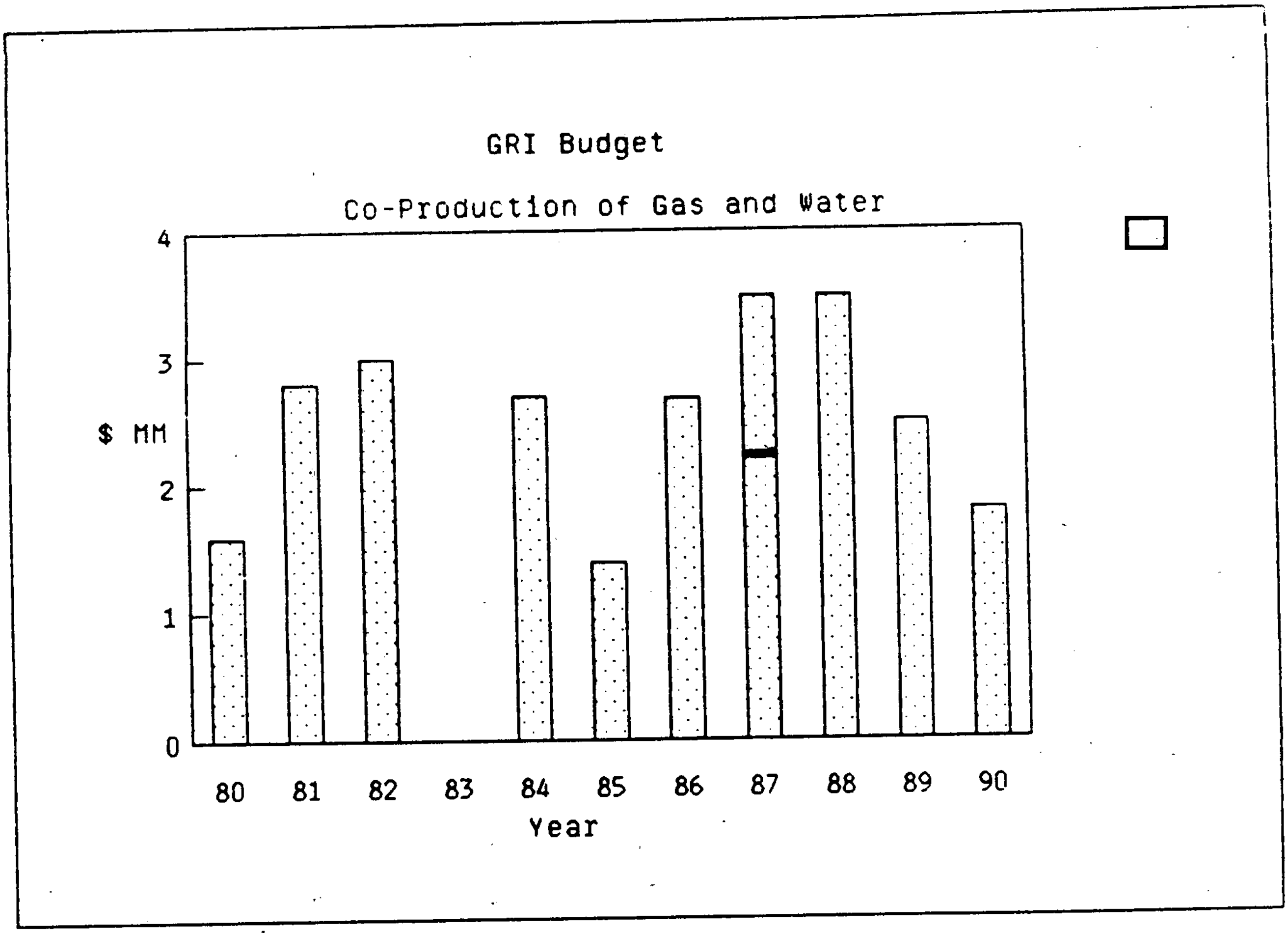


Figure III-5
Flow Diagram for Co-Production of Gas and Water Project Area (1.1.3)





GRI Budget
Co-Production of Gas and Water
4
3
$ MM
2
1
0
80
81
82
83
84
85
86
87
88
89
90
Year

DOE	GRI
Geopressured/Geothermal Energy Program	Co-Production of Gas & Water Program
Methane from Geopressured Aquifers Program	

Goal (DOE)

Stimulate commercial development by the private sector of the geopressured/geothermal resource.

- o Resource characterization
- o Total Energy recovery heat-pressure-gas
- o Environmental problems assessment
- o Engineering problems assessment
- o Reduce investment uncertainty
- o Answer technical questions

Goal (GRI)

Conduct Co-Production R&D projects of mutual interest to Industry and gas consumers.

Identify and verify potential supply of uncoventional natural gas from aquifer and wet reservoirs.

- o Focus on gas recovery
- o Quantative resource estimates
- o Evaluate economic factors
- o Environmental issue
- o Brine and chemical problems
- o Numerical Modeling
- o Reservoir Engineering/Management

Priority Ranking

1. Geopressured watered-out reservoirs
2. Hydropressured water-out reservoirs
3. Thin strangers/wet zones
4. Geopressured aquifer dissolved gas

Field Program

DOE	GRI
Conduct design well and well of opportunity tests.	Conduct R&D projects on wells provided by industry.
o Long term-High Risks projects	o Near/Mid Term Moderate Risk

Lab & Support Program

DOE	GRI
o Brine/Gas Chemistry	o Brine/Gas Chemistry
o Rock Mechanics	o Relative Permeability

AREAS OF POSSIBLE COORDINATION
DOE GEOPRESSURED-GEOTHERMAL/GRI CO-PRODUCTION PROGRAMS

<u>General Program</u>

- Resource Assessment/Identification/Catagorization
- Information/Reference Library
- Cataloging/Appraising Numerical Simulators available or are needed for co-production problems.

<u>Field Projects</u>

- DOE/GRI/Industry gas well test (i.e. Port Arthur Geopressured Watered-out Gas Reservoir)
- Hydropressured well test? (Depending on DOE program guidelines)
- Total Energy Use Test (i.e. Brazoria County Test with EPRI)

<u>Lab-Support Projects</u>

- P.V.T., Chemistry, Thermodynamics of Gas/Water
- Relative Permeability at High Water Saturation

O. APPENDIX 15

UT/BEG PROSPECT EVALUATION FOR CO-PRODUCTION

M. LIGHT/M. JACKSON/W. AYERS - BEG

GEOLOGY AND CO-PRODUCTION POTENTIAL OF SUBMARINE-FAN DEPOSITS ALONG THE GULF COAST OF EAST TEXAS AND LOUISIANA

by Mary L. W. Jackson, M. P. R. Light, and W. B. Ayers, Jr.

ABSTRACT

Four reservoirs containing dispersed gas were examined for their co-production potential. Reservoirs in the Port Acres and Ellis fields produce from the Hackberry Member of the Oligocene Frio Formation, and two reservoirs in the Esther field produce from the lower Miocene *Planulina* Zone. Log-pattern and lithofacies maps, together with stratigraphic position, suggest that the reservoirs are in ancient submarine-fan deposits. Dip-elongate, channel-fill sands are characteristic; reservoir sands pinch out along strike. Growth faults, common in the submarine slope setting, form updip and downdip boundaries, producing combination traps.

In the Ellis field, co-production accounts for 300 Mcf (8.5×10^6 m^3) of gas per day. The Port Acres field contains the largest remaining reserves, but other technical and economic factors limit co-production potential there. Recent drilling has extended primary production and delayed co-production in the Esther field.

*Project supported by the Gas Research Institute, Contract No. 5084-212-0924.

INTRODUCTION

During conventional production from a water-drive gas reservoir, mobile gas is removed from the gas cap. A considerable amount of dispersed gas remains in the water, however, after the field has watered-out (1). This dispersed gas can be recovered through co-production, or the simultaneous production of gas and water. During co-production, large amounts of water are pumped to the surface, lowering reservoir pressure and causing dispersed gas to expand; the gas then moves to the co-producing well and is produced with the water (2). If the reservoir has sufficient residual pressure and the pumped water can be disposed of easily, extended production of a field may be economically viable (1). To avoid costly well re-entry or drilling of new wells, co-production is best initiated in a watered-out reservoir before the wells have been plugged.

Four reservoirs with co-production potential were selected for detailed study. The reservoirs are located in the Port Acres (Texas), Ellis, and Esther (Louisiana) fields (fig. 1). The lower Hackberry and *Nodosaria* 3 reservoirs, in the Port Acres and Ellis fields, are productive from the Hackberry Member of the Frio Formation, and the two *Planulina* Zone reservoirs in the Esther field are productive from lower Miocene sands. Several of the factors that determine the suitability of a reservoir for co-production, such as porosity, permeability, and reservoir volume (3), relate to the geology of the reservoir.

Therefore, for each of the reservoirs selected for study, all available data were used to interpret the depositional setting of the reservoir sand, the trapping mechanisms, and the volume of the reservoir. Original gas in place and remaining reserves were calculated, and the co-production potential of each field was assessed.

HACKBERRY TREND

The Frio Formation (Oligocene) is a major progradational wedge of dominantly sandy sediment that extends from Texas to Louisiana. Previous workers divided the Frio into three units using log character; the Hackberry Member is laterally equivalent to middle Frio sediments (4). The upper boundary of the Hackberry sequence is marked by *Marginulina texana*; for the purpose of this paper the lower Hackberry will include the *Nodosaria blanpiedi* zone, although there is some dispute over the lower boundary of the Hackberry (5)(fig. 2).

The Hackberry Member was probably deposited as a submarine-fan complex (6); it is composed mainly of turbidite, or gravity-flow, deposits. The Hackberry Embayment, containing Hackberry submarine fans, extends from southeast Texas eastward to south-central Louisiana (4) (fig. 1). The updip limit of Hackberry sediments is the Hartburg flexure, which is more or less coincident with the oldest growth-faults in the Frio (5). The unit thickens basinward, attaining more than 3,000 feet (900 m)(7). The lower Hackberry is relatively sand-rich, with nearly continuous sand sequences up to 800 ft (240 m) thick; the upper Hackberry is almost entirely mud.

Depositional channel-sand axes trend northwest-southeast in Texas and north-south in Louisiana (4). Hackberry reservoir sands are highly lenticular and dip-elongate; they are an important producing trend in the Gulf Coast (5).

A model of submarine-fan sub-environments (8) linked with spontaneous potential log patterns representing the different sub-environments (4)(fig. 3) was used to interpret the environments present in the Port Acres and Ellis Hackberry reservoirs.

Port Acres Field

Introduction

The Port Acres field is located in east-central Jefferson County, Texas (fig. 1). Previous work on the Hackberry Member in this area of southeast Texas includes a report on the Frio Formation (9), a study on cores from two wells in Jefferson County (10), a discussion of geology and early production history of the adjacent Port Acres and Port Arthur fields (11), and most recently a report on depositional systems and structural controls of Hackberry sandstone reservoirs in Jefferson and Orange Counties (4).

Marker A4, based on log character and established in the Port Acres - Port Arthur area by Ewing and Reed (4)(fig. 2), was used in this study as the approximate top of the lower Hackberry Member (fig. 4). Reference to cross-sections from Ewing and Reed (4) aided correlation of the 66 well logs used in the Port Acres field study.

Production History and Structure

The productive area of the lower Hackberry reservoir in the Port Acres field is about 2,515 acres (1.0×10^7 m^2). At present, only one well produces gas and condensate from lower Hackberry sands; the field has been "substantially abandoned" since 1978 (3). The Hackberry "Main" sand, designated as the 10,500 lower Hackberry reservoir, has produced more than 307 Bcf (8.7×10^9 m^3)(12) since discovery in 1957. The Hackberry 10,450 sand, a stringer sand above the Hackberry Main sand, also has produced gas (fig. 4).

Gas in the reservoir is concentrated in the uppermost 140 feet (43 m) of lower Hackberry sands (fig. 4). Gas-bearing sands are separated from deeper water-bearing sands by a shale wedge which is 30 feet (9 m) or more in thickness.

A growth fault with up to 600 feet (180 m) of displacement separates the Port Acres field from the Port Arthur field to the east. Structure contours on top of the Hackberry Main sand show a pronounced anticline developed on the upthrown side of a minor fault; this fault forms a seal on the southern side of the reservoir (fig. 5). Reservoir sands decrease rapidly in thickness to the north and east of the field, and this pinchout completes the seal on the reservoir.

A sand distribution map of the the Port Acres - Port Arthur area defines a canyon axis to the northeast of the Port Acres field containing sand thicknesses greater than 600 feet (180 m)(1)(fig. 6). An arm of the canyon-fill sand extends to the south into the Port Acres field, and is prominent east of the main fault (fig. 7). However, this area of thicker sands does not contain the most gas. Comparison between Figure 5 and Figure 8 shows that the western, shallower side of the field, a broad area with 150 to 200 feet (46 to 61 m) of sand thickness, is the main gas-bearing area; structural control is more important than sand thickness in the main part of the reservoir. Sand thickness decreases rapidly to the west where Hackberry sediments are confined by the canyon walls.

Depositional Setting

Dip-alignment of Hackberry sands in the Port Acres area is evident (figs. 6 and 7), suggesting deposition in the proximal portion of the submarine-fan system. The log patterns suggest a braided channel system with several incised channel-fill sands (fig. 9). Spontaneous potential (SP) log patterns of the Hackberry Main sand in the central part of the field are blocky, suggesting channel-fill sands; patterns on the eastern half of the field show thinner, upward-fining sands, suggesting intermediate suprafan deposits. These sands pinch out in the eastern part of the field (fig. 9) as well as to the north, where they interfinger with sand-poor overbank deposits.

Ellis Field

Structure and Field History

The Ellis field is located in Acadia Parish, Louisiana (fig. 1). Major growth faults bound the field on the northwest and on the south (7,13)(fig. 10). The lower Hackberry, *Nodosaria* 3 reservoir sands pinch out and are faulted downward on the east, sealing them against slope muds. A fault with less than 150 feet (46 m) of displacement crosses the reservoir from northeast to southwest, separating it into two sections which maintain communication of fluids (3). The combined productive area of the reservoir is about 110 acres (4.4×10^5 m^2). Approximately 45 Bcf (1.3×10^9 m^3) of gas have been produced since field discovery in 1953 (12). The reservoir was shut-in in 1973, but one well was re-opened in 1977 and is now co-producing gas and water from the *Nodosaria* 3 sand in the northern part of the field (3). In addition, the *Nonion struma* and *Nodosaria* 5 sands, above and below the *Nodosaria* 3, produce both oil and gas from the Hackberry Member.

Depositional Environment and Gas Occurrence

The regional depositional setting of the *Nodosaria* 3 sand is difficult to determine because only 17 wells have been drilled in the *Nodosaria* Zone of the Ellis field and lithofacies maps of nearby areas were unavailable. An inferred submarine-fan channel system trends generally north-south, indicating dip-alignment of Hackberry sand bodies similar to that in the Port Acres field (fig. 11). The log-pattern map shows two areas of channel deposits separated by an area of inferred overbank sediments. The northern, gas-rich end of the *Nodosaria* 3 reservoir coincides with incised channel-fill and braided channel-fill sands (figs. 11 and 12). Similar, braided channel sands in the southern part of the field contained much less gas, however, possibly due to structural control. The original gas-water contacts for the *Nodosaria* 3 sand are -11,725 ft (-3574 m) for the southern part of the reservoir and -11,745 (-3580 m) for the northern part.

PLANULINA TREND

The lower Miocene *Planulina* trend is located basinward of the middle Frio Hackberry trend (figs. 1 and 2). It extends more than 150 miles (240 km) westward from the Mississippi River to southeast Texas (14,15). Regional dip on top of the *Planulina* Zone is to the south at about 385 ft/mi (73 m/km) in Vermillion Parish, Louisiana, and the zone thickens southward (14). The increase in thickness is partially attributable to increased sediment accumulation across growth faults that have vertical displacements as great as 1,000 ft (305 m)(15,16). Hydrocarbons in the

Planulina trend are found in anticlinal, domal, stratigraphic, and combination traps.

Initial discovery of gas in *Planulina* sands was made in 1945, in Cameron Parish, Louisiana, at the western end of the trend. Development of the trend was slow for the next 20 years because of failures caused by inadequate drilling techniques and geologic complexity. Improvements in drilling technology and exploration techniques, and a better understanding of the geology, have increased the success ratio and have generated more interest in the trend since the mid-1960's (15).

The term "*Planulina* Zone" is informally used by Gulf Coast geologists to specify a lower Miocene wedge of light- to dark-gray marine shale with interbedded sands. The *Planulina* Zone is recognized by the presence of the intermediate neritic to upper bathyal *Planulina palmerae* microfaunal assemblage, but contacts are uncertain and correlations are difficult and inconsistent (14,15,17,18).

Efforts to determine the origin of *Planulina* sands led to suggestions that they were deposited in deltaic distributary channels (14,15,18), offshore bars (16,19), continental shelf sheet-sand deposits (14), or submarine fans (20). Because of the complexity of the stratigraphy and structure, clarification of the genesis of these deep-water sands requires an integrated regional study. Nevertheless, the *Planulina* Zone is part of a major Miocene progradational wedge. Within this wedge, the deep-water *Planulina* Zone lies basinward of, and below, shales containing the intermediate neritic *Siphonina davisi* fauna, which is in turn overlain by a thick regressive sequence of brackish through continental strata (15,18); the *Planulina* Zone overlies shales containing the upper bathyal Abbeville faunal assemblage. The deep-water origin of the *Planulina* Zone and its position in the sequence of strata suggest that the *Planulina* strata were deposited on the outer continental shelf to upper slope. From these observations and from the analysis of spontaneous potential well-log patterns, we infer that the *Planulina* sands were deposited in a setting similar to that of the Hackberry.

Esther Field

Field History, Geology, and Methodology

The Esther field, located in the *Planulina* trend in central Vermillion Parish, Louisiana (fig. 1), was discovered in 1977. Since production began in 1978, 41 Bcf (1.2×10^9 m^3) of gas and 459,900 bbl (73,080 m^3) of condensate have been produced (12) from two *Planulina* reservoirs, the 13,700 sand and the 14,060 sand. Recently, the field has been extended to the northeast.

In the Esther field, approximately 1,000 ft (305 m) of marine shale with a few interbedded sands separates the 13,700 sand from the overlying paralic and continental strata. Top of geopressure is near the top of the marine shale at about 12,700 ft (3,870 m)(3); the *Planulina* sands are geopressured. The 13,700 sand is separated from the underlying 14,060 sand by 200 to 250 ft (60 to 75 m) of mudstone.

A structure map (fig. 13) was drawn on top of the Cristellaria 5 sand which is approximately 1,800 ft (550 m) above the 13,700 sand. It is the closest mappable horizon to the Planulina sands. The Esther field lies in an anticlinal trap that formed on the south side of a major northeast-trending growth fault which offset the Cristellaria 5 sand by 300 to 400 ft (90 to 120 m).

Because few geophysical well logs were available -- 9 penetrate the 13,700 sand and 8 test the 14,060 sand -- and because the wells are located in a line nearly parallel to inferred paleostrike, interpretations of structure and of sand-body geometry and trends are tentative. Lacking regional structural and lithofacies maps, but recognizing the similarities between the Planulina and Hackberry depositional setting, we evaluated the Esther field using a submarine-fan depositional model. This model is consistent with that of Lock (20).

Data from geophysical well logs were used to make structure, net-sand, net-gas-sand, and log-pattern maps for the 13,700 and 14,060 reservoirs. In view of the similarities between the 13,700 and 14,060 reservoirs, only the former reservoir will be discussed.

Depositional Environment and Gas Occurrence, 13,700 Sand

The structure map on top of the 13,700 sand (fig. 14) and cross section B-B' (fig. 15) demonstrate the fault-bounded anticlinal trap and the gas-water contact. They also show that the field is bisected by a minor non-sealing (3) fault with about 150 ft (45 m) vertical displacement. If, indeed, the minor fault is nonsealing, it probably does not bisect the entire field as shown, in view of the offset of the reservoir sands against mudstone (fig. 15).

The net thickness of sands (fig. 16) ranges from 25 to 77 ft (8 to 23 m). Sand thicknesses are about 10 ft (3 m) greater on the downthrown side of the minor fault, suggesting syndepositional fault movement. Dip-elongate (north-south) sand-body trends are inferred from the regional paleoslope and from the Hackberry analogue. Spontaneous potential (SP) response for the 13,700 sand (fig. 17) shows inferred braided channel-fill sands (blocky SP log patterns with shale partings) and incised channel-fill sands (blocky SP log pattern with few shale partings) coincident with dip-elongate sand-body trends of the lithofacies map (fig. 16). Two possible channel systems are identified. The larger system encompasses the eastern third of the field; the smaller system lies in the western third of the field (fig. 17). Intermediate suprafan (upward-coarsening log patterns) and overbank (serrate SP log patterns) deposits are marginal to the channel-fill sands.

The net thickness of gas-bearing sand is estimated to range from 6 ft to more than 40 ft (1.8 to 12 m)(fig. 18). High values of net gas sand (fig. 18) coincide with mapped channel axes (fig. 16). The original gas-water contact for the 13,700 sand is at -13,763 ft (-4,195 m)(figs. 15 and 18). The area of the reservoir is 1,420 acres (5.74×10^6 m^2) and initial gas in place was 71 Bcf (2.0×10^9 m^3)(table 1).

RESERVE ESTIMATES

Net-gas-sand maps were planimetered and initial gas in place was calculated for the lower Hackberry, Nodosaria, and Planulina reservoirs. Initial gas reserves were estimated by a volumetric method (Z. Lin, personal communication, 1985). This method requires a knowledge of the initial (at discovery) reservoir fluid pressure and temperature, average porosity, gas saturation, volume of gas-saturated formation and gas gravity (table 1). From these data, first the pseudocritical and pseudoreduced temperatures and pressures, then the compressibility factor for natural gas (Z), and finally the gas formation volume factor (Bg) can be derived (21,22,23,24).

The equation used to estimate the initial gas in place (IGIP) is:

$$IGIP = (43,560)(A)(h)(f)(1-Sw)(Bg) \ldots\ldots\ldots\ldots (1)$$

Where A = area of field in acres

h = effective net pay thickness in feet

f = porosity fraction

Sw = water saturation fraction

Bg = gas formation volume factor (ft^3/Scf) (25).

The remaining natural gas available for co-production (GCP) is estimated by the following equation:

$$GCP = IGIP - \text{total production to date.} \ldots\ldots (2)$$

Additional gas also may be produced from solution as a result of the large pressure drawdown sustained during co-production. However, methane solubility is estimted at 22 Scf (4,900 m^3) per bbl of water at the Port Acres field; hence, only 110 Mscf/day (3.1 x 10^6 m^3/day) of solution gas could be obtained from a well producing methane-saturated formation water at a rate of 5,000 bbl/day (800 m^3/day)(26). This volume of gas, which is insignificant compared to potential free gas production from the three fields, has been disregarded in the reserve estimates.

The initial free gas reserve estimate for the Port Acres field is 378 Bcf (1.1 x 10^{10} m^3), with 71 Bcf (2.0 x 10^9 m^3) of remaining gas in place (table 1). Earlier estimates by Halbouty and Barber (27) ranged from 400 to 500 Bcf (1.1 to 1.4 x 10^{10} m^3) whereas Howell and others (3) indicate a range of 326 to 374 Bcf (0.9 to 1.1 x 10^{10} m^3) of remaining gas in place. They estimate an additional recovery of some 9.6 to 28.2 Bcf (2.7 to 7.9 x 10^8 m^3) using co-production techniques which would require the removal of up to 20 million bbl (3.0 x 10^6 m^3) of water (3).

The initial free gas reserve estimates for the Nodosaria 3 reservoir (Ellis field) vary from 48 to 56 Bcf (1.3 to 1.6 x 10^9 m^3) with some 7 to 11 Bcf (2.0 to 3.1 x 10^8 m^3) of gas presently remaining in place when calculated by equation 2 (table 1). Five to 10 Bcf (1.4 to 2.8 x 10^8 m^3) of remaining gas in place was estimated using p/z data (Z. Lin, personal communication, 1985). Howell and others (3) indicate that a gas production rate of 1,000 Mcf/day (2.8 x 10^7 m^3/day) and 3,000 bbl (477 m^3) of water per day can be sustained in the Ellis field for 10 years, which gives a total volume of 3.65 Bcf (1.0 x 10^8 m^3) of co-produced gas.

Initial gas in place in the Planulina reservoirs (total for the 13,700 and 14,060 sands) is estimated at 139 Bcf (3.9 x 10^9 m^3) with 97 Bcf (2.7 x 10^9 m^3) of gas remaining in place (table 1). At least 7 Bcf (2.0 x 10^8 m^3) of additional gas can be recovered from the Esther field by producing up to 10,000 bbl (1,589 m^3) of water per day (3).

CONCLUSIONS

The submarine-fan depositional setting of Hackberry and *Planulina* reservoir sands controls several reservoir properties. Gas reservoirs are dip-elongate, channel-fill sands which pinch out laterally into overbank muds. Growth faults, common in the submarine slope environment, bound the fields on one or more sides, producing combination traps. The trapping mechanisms, growth faults and pinchouts, restrict reservoir size, but they also retard water invasion during pumping, which may allow for increased mobility of dispersed gas.

Of the three co-production fields studied, the Port Acres has the largest remaining reserves, but other factors, such as leasehold costs, sand production controls, and artificial lift requirements, (3) affect the economic potential of co-production in this reservoir. Eaton Operating Co., Inc. estimates that if 6 wells are used in a co-production project, each well should need to pump only 1,000 bbl/day (159 m^3/day)(3).

Secondary gas recovery is now underway at the Ellis field. A well in the northern part of the field was re-activated in 1977; water production since then has been as high as 2,400 bbl/day (381 m^3/day)(3). Recently the well has produced 1,200 bbl (191 m^3) of water and 300 Mcf (8.5 x 10^6 m^3) of gas per day, and it is estimated that reduced gas saturation will compensate for declining reservoir pressure to extend co-production through 1996 (3).

Some wells in the Esther field are watering out and are suited for co-production. Primary production in the Planulina Zone continues, however, and additional wells have recently been completed on the northeast side of the reservoir. Co-production possibilities, therefore, may be re-evaluated at a later date.

REFERENCES

1. Gregory, A. R., Lin, Z. S., Reed, R. S., Morton, R. A., and Ewing, T. E.: Enhanced gas recovery from watered-out reservoirs -- -Port Arthur field, Jefferson County, Texas, The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 142, (1984) 58.
2. Gas Research Institute: Co-production of natural gas and Water, Program information brochure, (undated) 19.
3. Howell, R. W., Peterson, K. P., Anderson, L. L., and Parisi, W. A.: Co-production of gas and water, fourth year annual report prepared for Gas Research Institute under contract no. 5084-212-0981, The University of Texas at Austin, Bureau of Economic Geology (1985) 63.
4. Ewing, T. E., and Reed, R. S.: Depositional systems and structural controls of Hackberry sandstone reservoirs in southeast Texas, The University of Texas at Austin, Bureau of Economic Geology Geological Circular No. 84-7 (1984) 48.

5. Le Vie, D. S., Jr.: "Interdomal sediment ponding: a new lower Hackberry play?," Gulf Coast Assoc. of Geological Societies Trans., v. 35 (1985) 171-178.

6. Paine, W. R.: "Stratigraphy and sedimentation of subsurface Hackberry wedge and associated beds of southwestern Louisiana," Am. Assoc. Petrol. Geol. Bull., v. 52, no. 2 (1968) 322-342.

7. Paine, W. R.: "Geology of Acadia and Jefferson Davis Parishes," State of Louisiana Department of Conservation, Louisiana Geological Survey Geological Bull., no. 36 (1962) 277.

8. Walker, R. G.: "Facies models 8, turbidites and associated coarse clastic deposits," in Walker, R. G., ed., Facies models, Geological Association of Canada, Geoscience Canada Reprint series 1 (1979) 91-103.

9. Reedy, F. Jr.: "Stratigraphy of the Frio Formation, Orange and Jefferson Counites, Texas," Am. Assoc. Petrol. Geol. Bull., v. 33, no. 11 (1949) 1830-1858.

10. Berg, R. R., and Powers, B. K.: "Morphology of turbidite-channel reservoirs, lower Hackberry (Oligocene), southeast Texas," Gulf Coast Assoc. of Geological Societies Trans., v. 30 (1980) 41-48.

11. Halbouty, M. T., and Barber, T. D.: "Port Acres and Port Arthur fields Jefferson County, Texas," Gulf Coast Assoc. of Geological Societies Trans., v. 11 (1961) 225-234.

12. Dwight's Energydata Co.: Natural gas well production histories, active and inactive wells, Lafayette District no. 12, Louisiana, Richardson, Texas, v. 3. (1985).

13. Sun Oil Co.: "Structural top, Nonion struma A sand," Louisiana Department of Conservation Docket no. 63-411, Exhibit no. 2. (1963).

14. Goheen, H. C.: "Sedimentation and structure of the Planulina-Abbeville trend, South Louisiana," Gulf Coast Assoc. of Geological Societies Trans., v. 9 (1959) 91-103.

15. Sloane, B. J.: "Recent developments in the Miocene Planulina gas trend of South Louisiana," Gulf Coast Assoc. of Geological Societies Trans., v. 21 (1971) 199-210.

16. Gotautas, V. A., Gordon, G. E. Johnson, Johnnie, and Lee, Clyde: "Southwest Lake Arthur field, Cameron Parish, Louisiana," in King, R. E., ed., Stratigraphic oil and gas fields, Am. Assoc. of Petrol. Geol. Memoir No. 16 (1972) 389-398.

17. Limes, L. L., and Stipe, J. C.: "Occurrence of Miocene oil in South Louisiana," Gulf Coast Assoc. of Geological Societies Trans., v. 9 (1959) 77-90.

18. Brunhild, S. R.: "Depositional and structural reconstruction of southwest Louisiana Oligo-Miocene strata: a temporal-spatial approach," Gulf Coast Assoc. of Geological Societies Trans., v. 34 (1984) 9-31.

19. Sonnier, Marc: "Chalkley field, Cameron Parish," Gulf Coast Assoc. of Geological Societies Trans., v.28 (1978) 581-588.

20. Lock, B. E.: "Towards a better understanding of Gulf Coast Miocene deep water sediments," Gulf Coast Assoc. of Geological Societies Trans., v. 32 (1982) 283-288.

21. Brown, G. G., Katz, D. L., Oberfell, G. B., Alden, R. C.: Natural gasoline and volatile hydrocarbons, Natural Gasoline Association of America, Tulsa, OK (1948) 44.

22. Carr, N. L., Kobayashi, R., and Burrows, D. B.: "Viscosity of hydrocarbon gases under pressure," Am. Inst. of Mining Engineers, v. 201 (1954) 264-270.

23. Craft, B. C., and Hawkins, M. F.: Applied petroleum reservoir engineering, Prentice-Hall, Englewood Cliffs, New Jersey, (1959) 437.

24. Standing, M. B., and Katz, D. L.: "Density of natural gases," Am. Inst. of Mining Engineers Trans., v. 146 (1942) 140-149.

25. Finley, R. J., Dutton, S. P., Lin, Z., and Saucier, A. E.: The Travis Peak (Hosston) Formation: geologic framework, core studies, and engineering field analysis, topical report prepared for Gas Research Institute under contract no. 5082-211-0708, The University of Texas at Austin, Bureau of Economic Geology (1985) 233.

26. Gregory, A. R.: Pressure, temperature, and salinity plots, The University of Texas at Austin, Bureau of Economic Geology Open File Report No. GRIM FW211-035 (1980) unpaginated.

27. Halbouty, M. T., and Barber, T. D.: "Port-Acres Port-Arthur fields Jefferson County, Texas," _in_ Denham, R. L., ed., _Typical oil and gas fields of southeast Texas_, Houston Geological Society (1962) 169-173.

28. Harrison, F. W.: "Esther field, structure on 13,700' sand," Louisiana Department of Conservation, Docket No. 81-616, Exhibit No. 5 (1981).

Table 1. Reserve calculations, Port Acres, Ellis, and Esther fields

Trend	Hackberry trend		Planulina trend	
Field	Port Acres	Ellis	Esther	
Reservoir	Lower Hackberry	*Nodosaria* 3	13,700 ft	14,060 ft
Initial Reservoir Temperature (°F)	225	225.2	260	265
Initial Reservoir Pressure (psia)[+]	9,015	9,720	11,500	11,700
Gas gravity (air = 1)	0.626	0.7	0.65	0.65
Gas saturation	0.7	0.8	0.65	0.65
Porosity	0.29	0.3	0.25	0.25
Pseudo-reduced temperature	1.87	1.91	1.92	1.94
Pseudo-reduced pressure	13.46	14.57	17.19	17.49
Compressibility factor, Z	1.33	1.38	1.57	1.53
Gas formation volume factor, Bg (ft^3/SCF)	350.32	363.51	359.63	372.86
Volume of field (acre-ft)	122,044	12,600	27,782	25,711
IGIP (Bcf)	378	48-56	71	68
Total production (Bcf)*	307.46	45.24	16.35	25.09
Remaining gas in place (Bcf)	70	3-11	54	43

[+] from Howell and others, (16)

* from Dwight's (6)

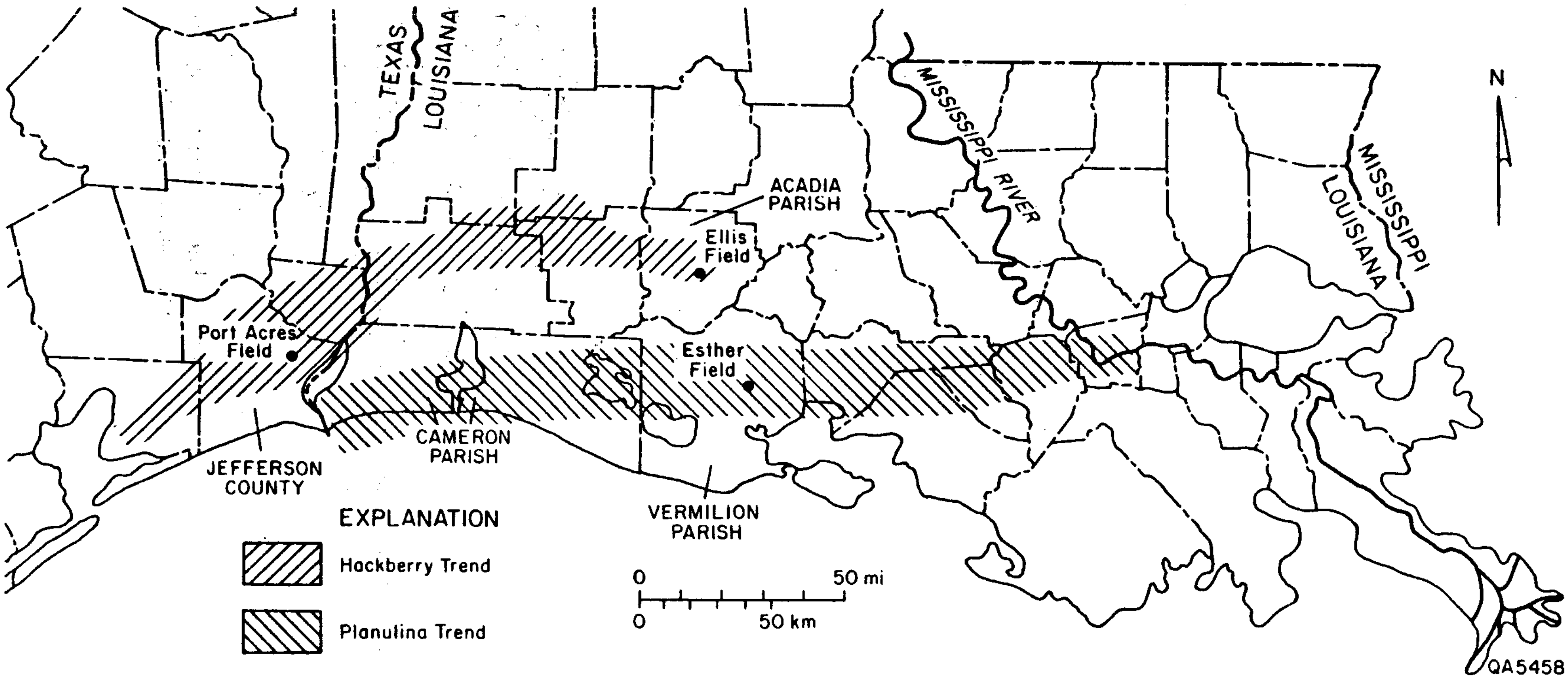


Figure 1. Hackberry and _Planulina_ trends, Louisiana and Texas.

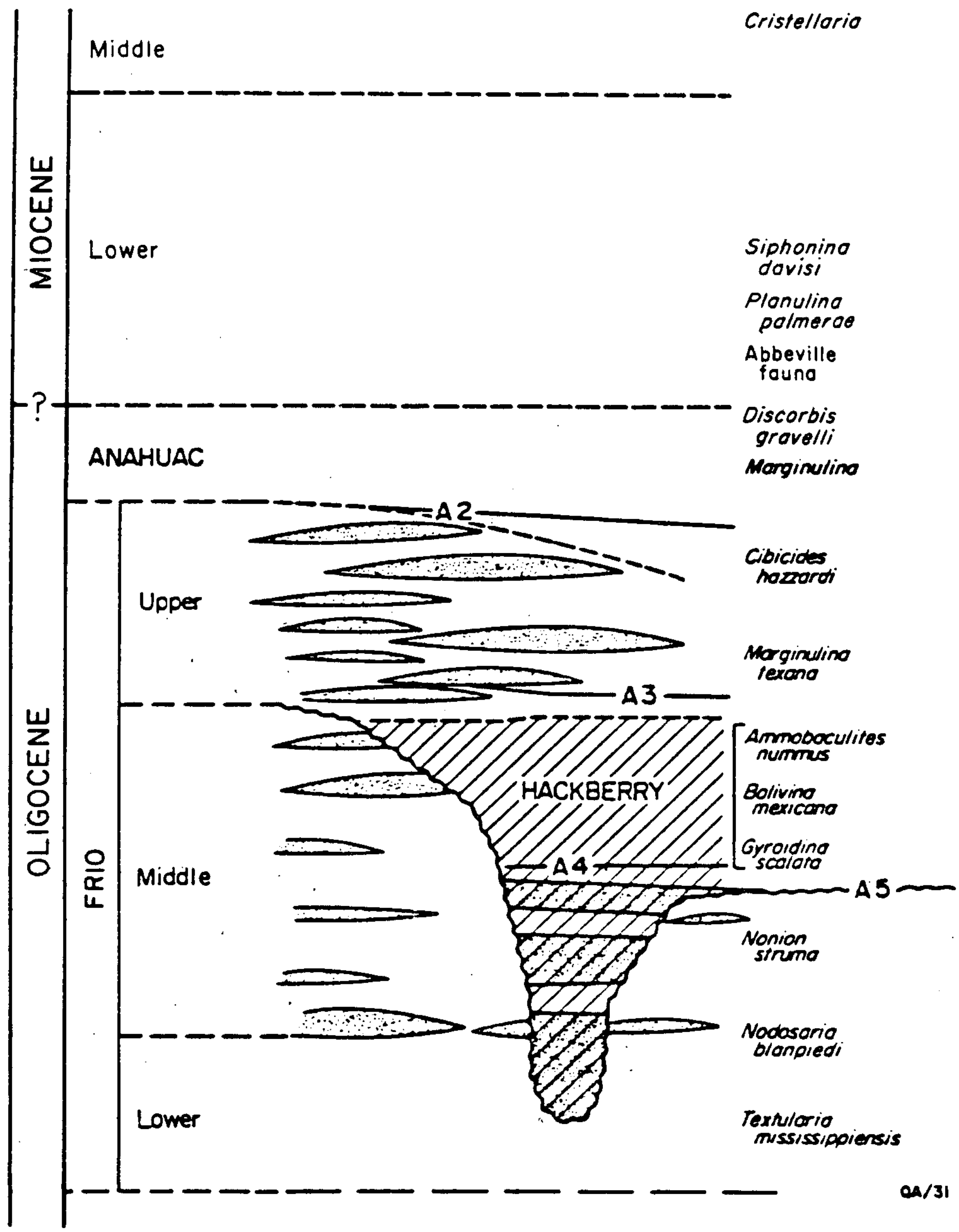


Figure 2. Frio and Hackberry stratigraphy, index fossils, and electric-log marker horizons (A2-A5), modified from Ewing and Reed (4).

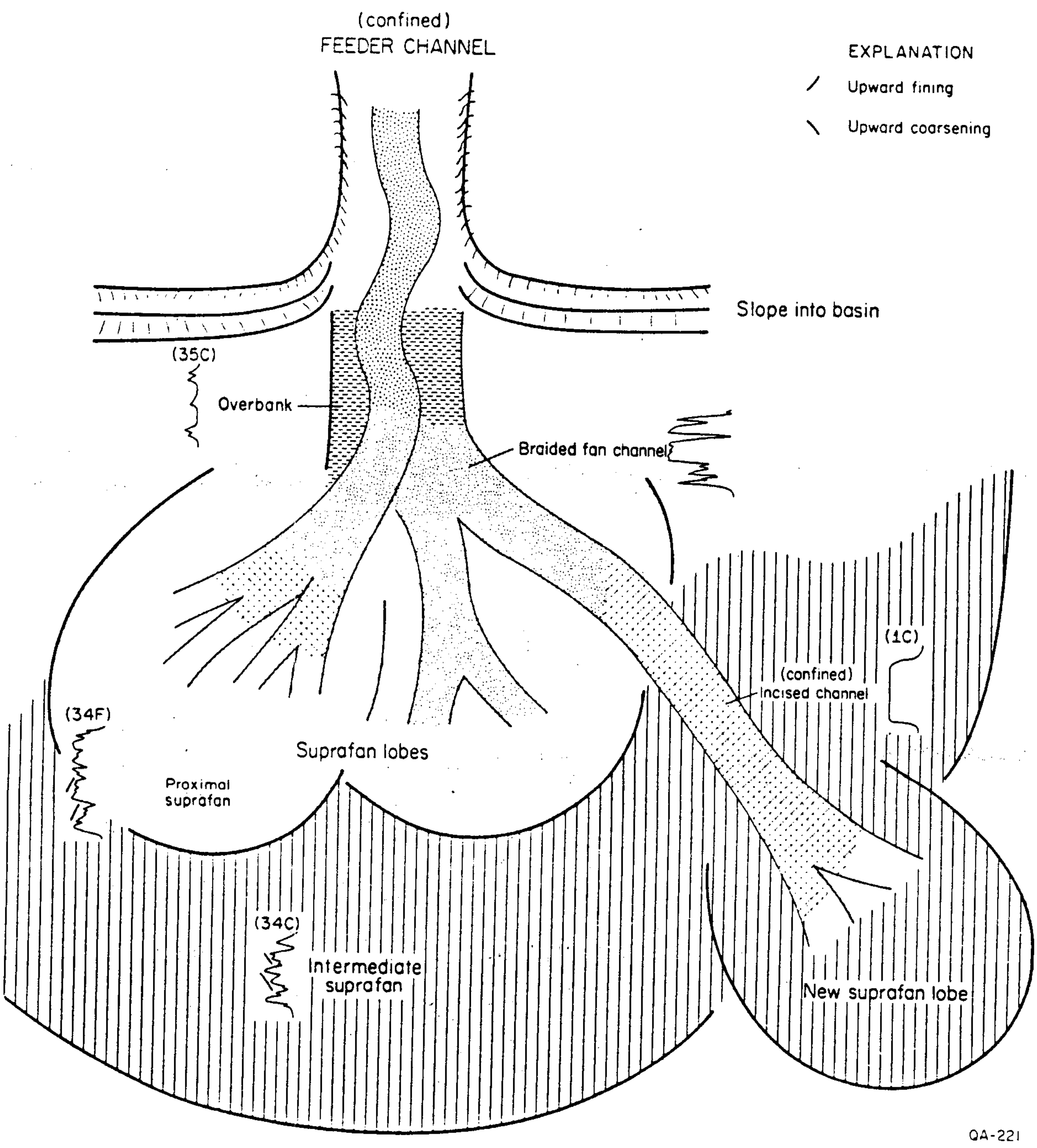


Figure 3. Submarine-fan environments and representative log patterns, from Ewing and Reed (4) after Walker (8).

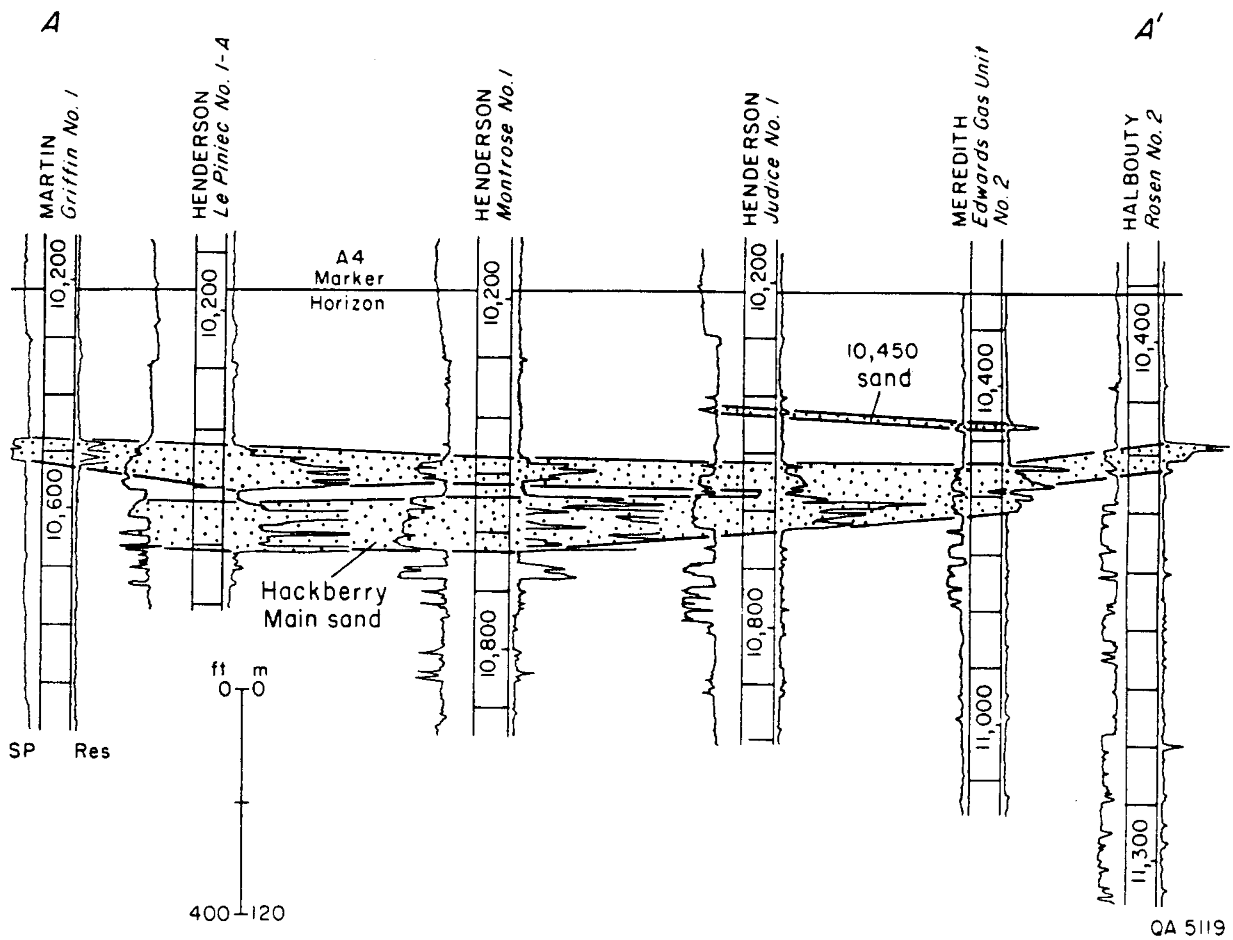


Figure 4. Cross-section through the Port Acres field. For location of section, see Figure 8.

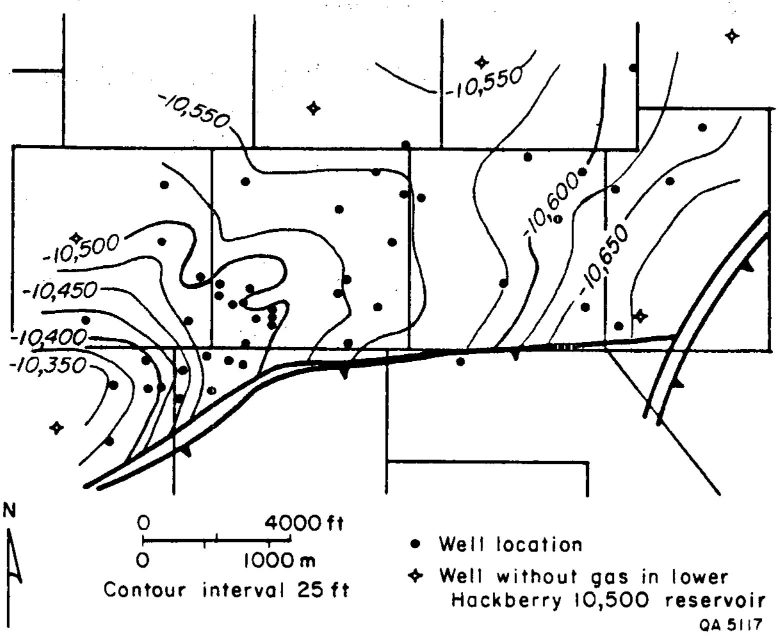


Figure 5. Structure map on the top of the Hackberry Main sand, Port Acres field.

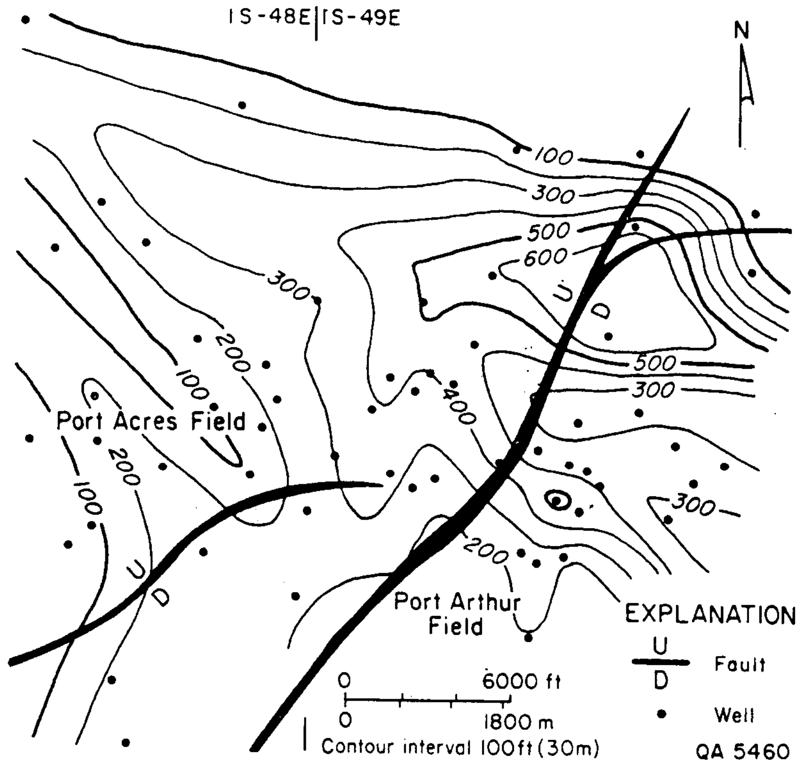


Figure 6. Net-sand distribution in the lower Hackberry sequence, Port Acres - Port Arthur area, from Gregory and others (1).

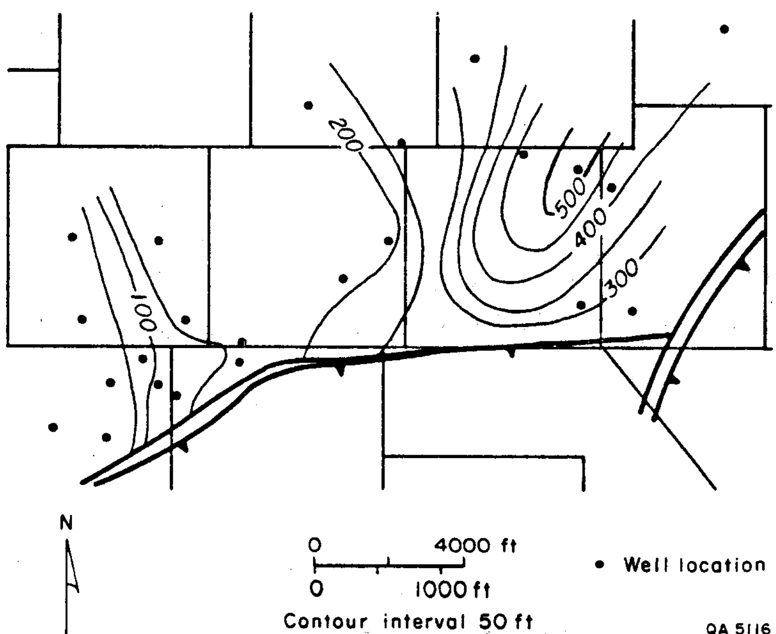


Figure 7. Net-sand map of the lower Hackberry interval, Port Acres field.

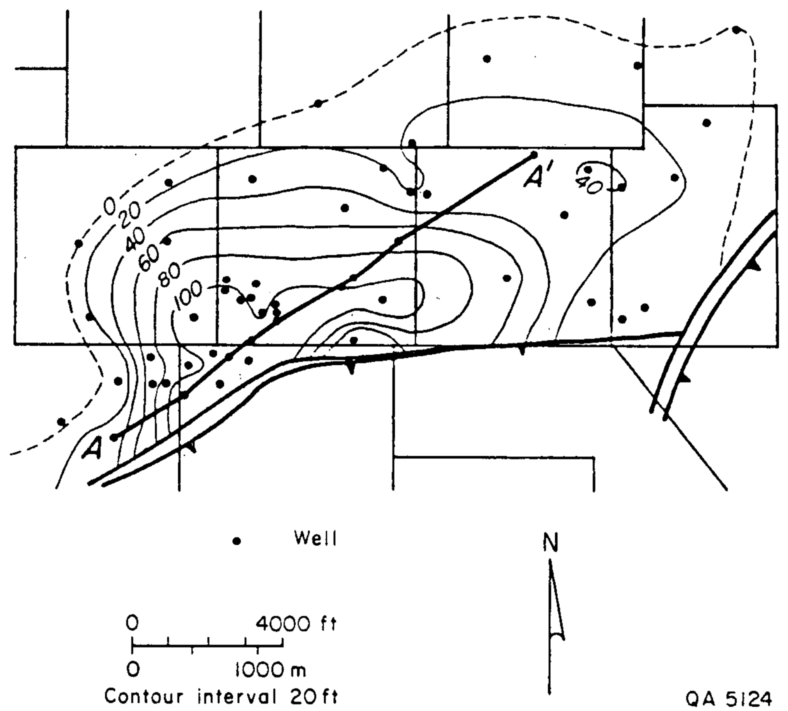


Figure 8. Net-gas-sand map, Hackberry lower reservoir, Port Acres field.

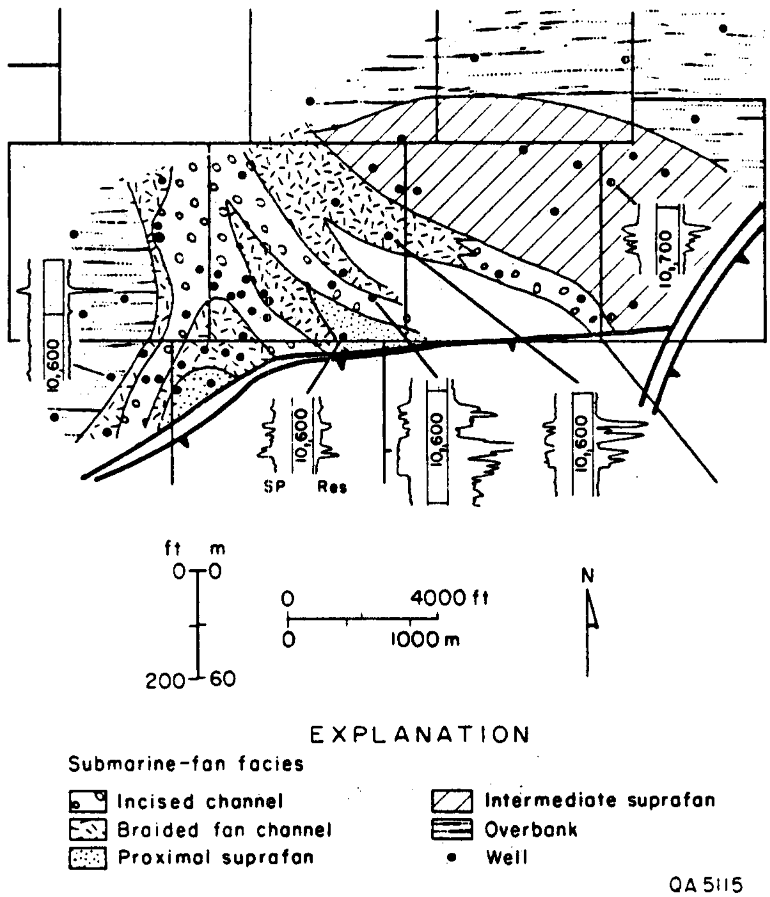


Figure 9. Log pattern map, Hackberry lower reservoir, Port Acres field.

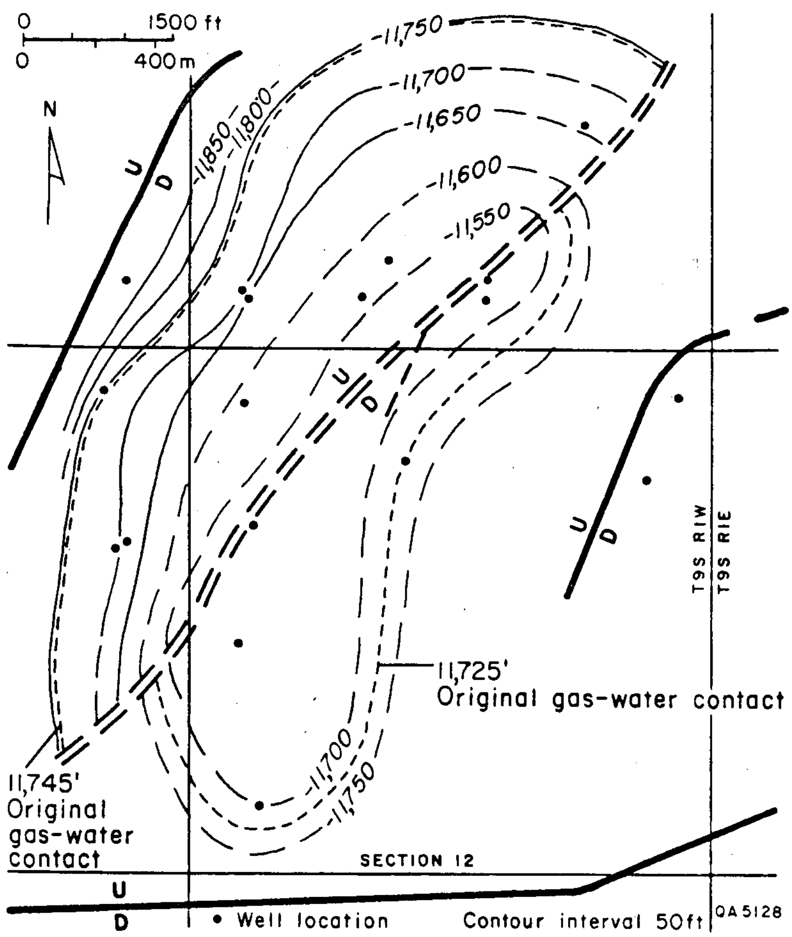


Figure 10. Structure map, top of Nodosaria 3 sand, Ellis field.

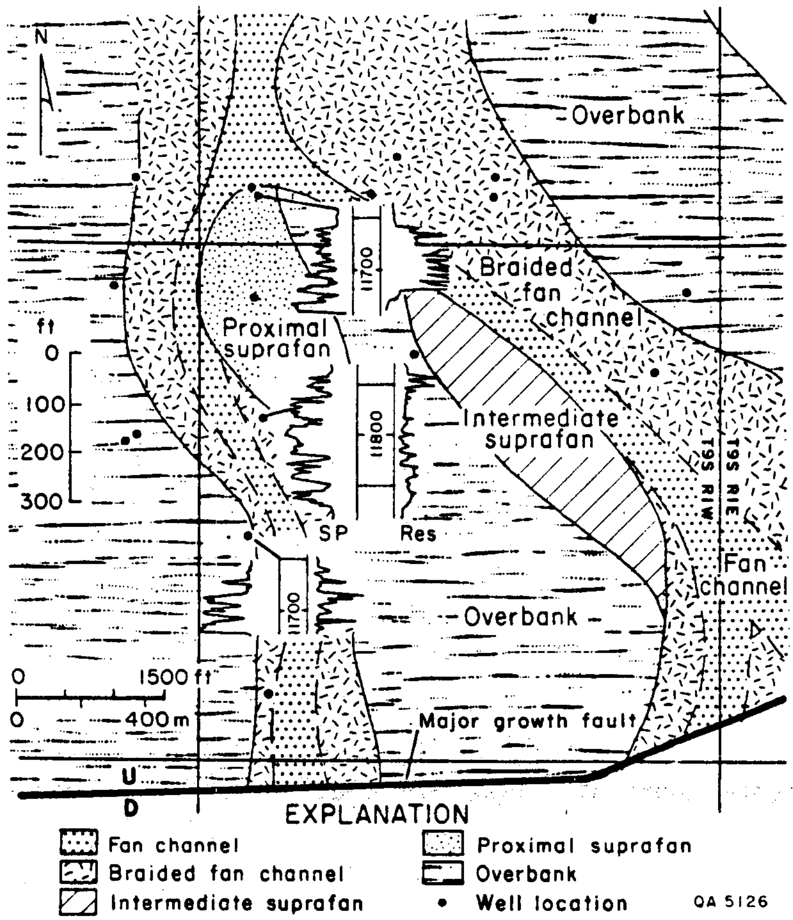


Figure 11. Log-pattern map, Nodosaria 3 sand, Ellis field.

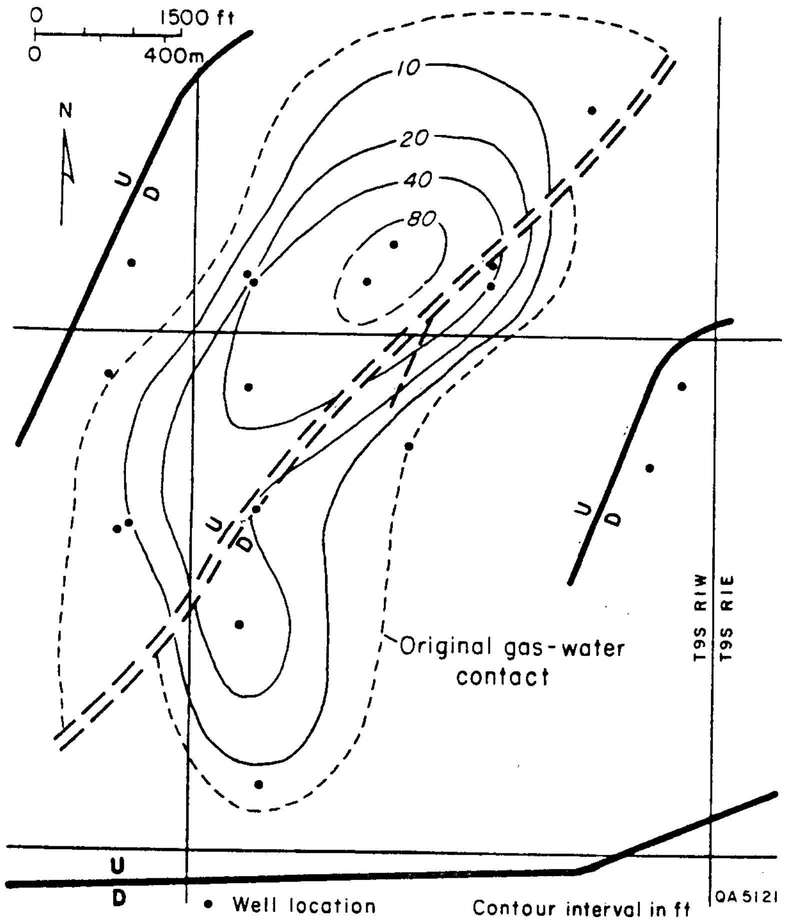


Figure 12. Net-gas-sand map, <u>Nodosaria</u> 3 sand, Ellis field.

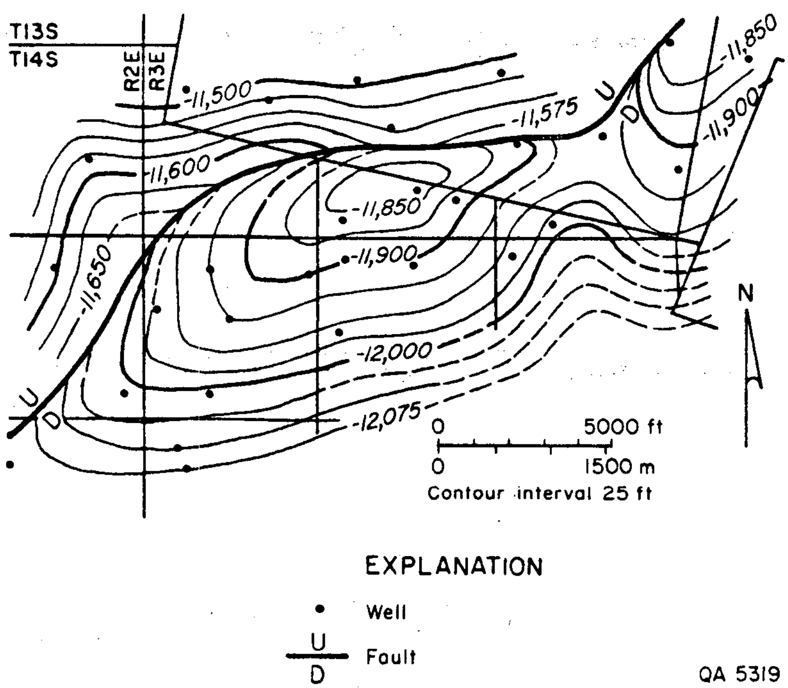


Figure 13. Structure on top of the *Cristellaria* 5 sand. The Esther field formed in a fault-bounded anticline; fault modified from Harrison (28).

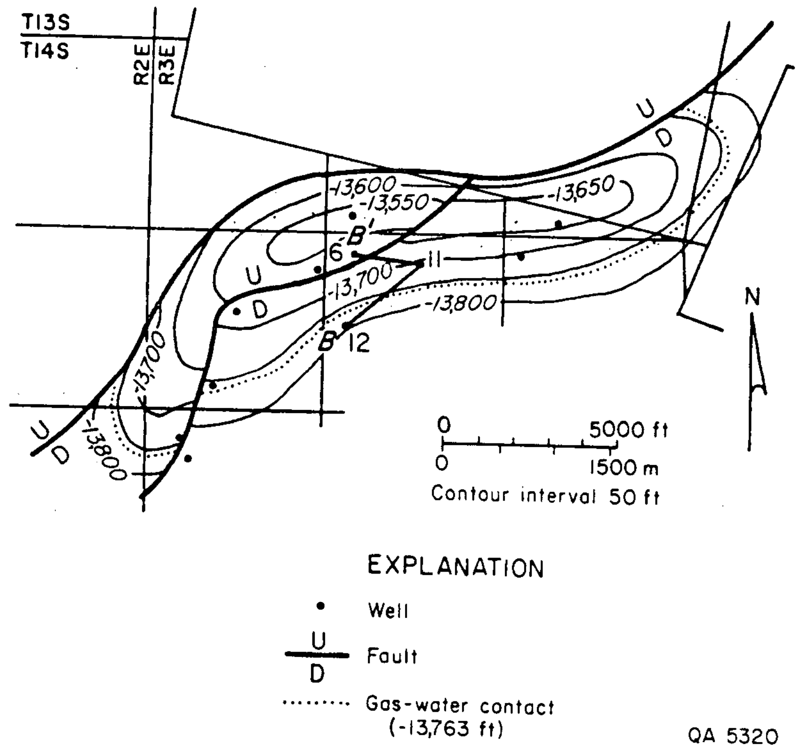


Figure 14. Structure map on top of the 13,700 sand. Anticlinal structure is crossed by a minor fault; faults modified from Harrison (28).

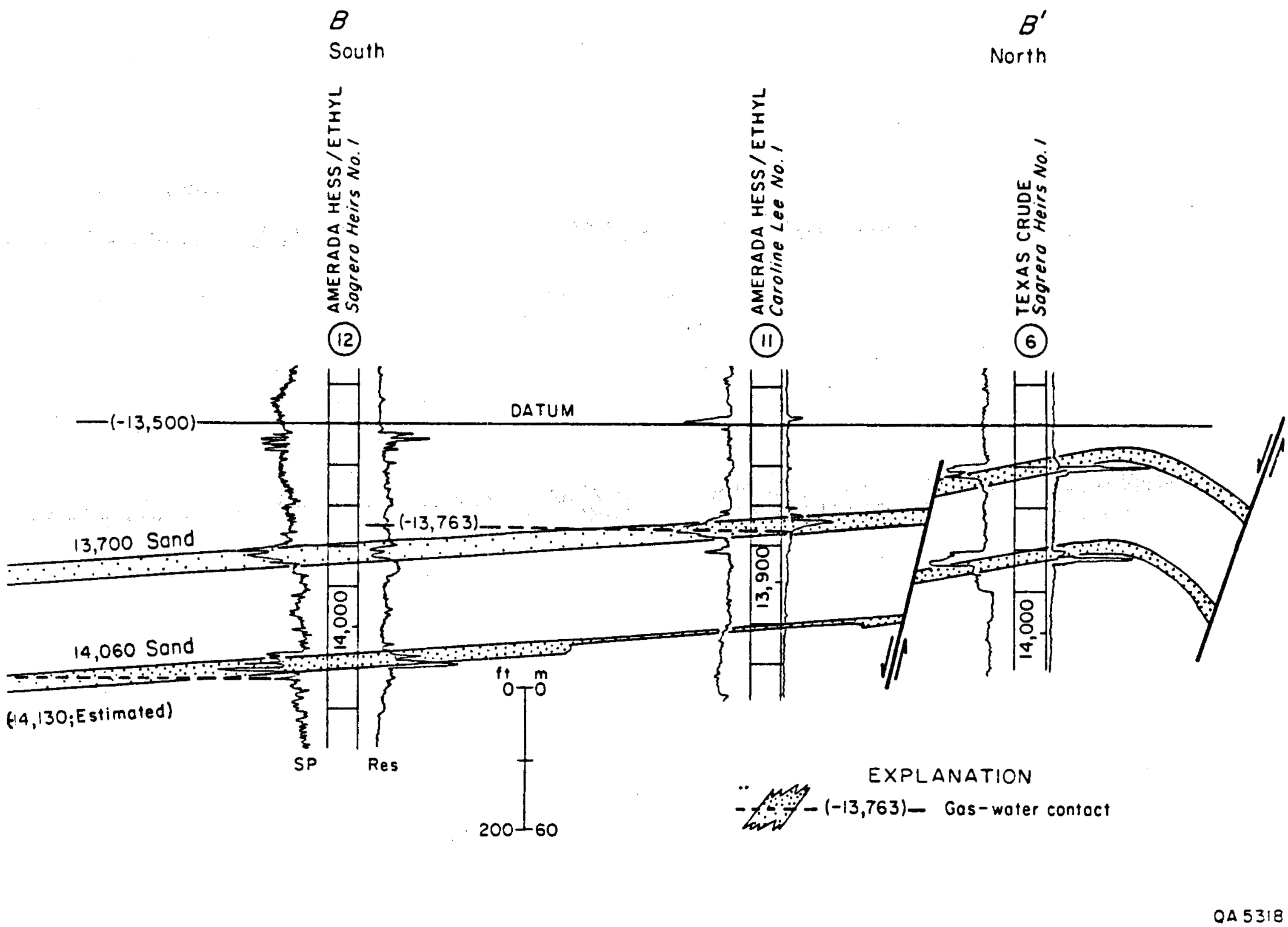


Figure 15. Cross-section B-B'. The Esther field formed in a fault-bounded anticline. A minor fault offsets reservoir sands. See Figure 14 for location.

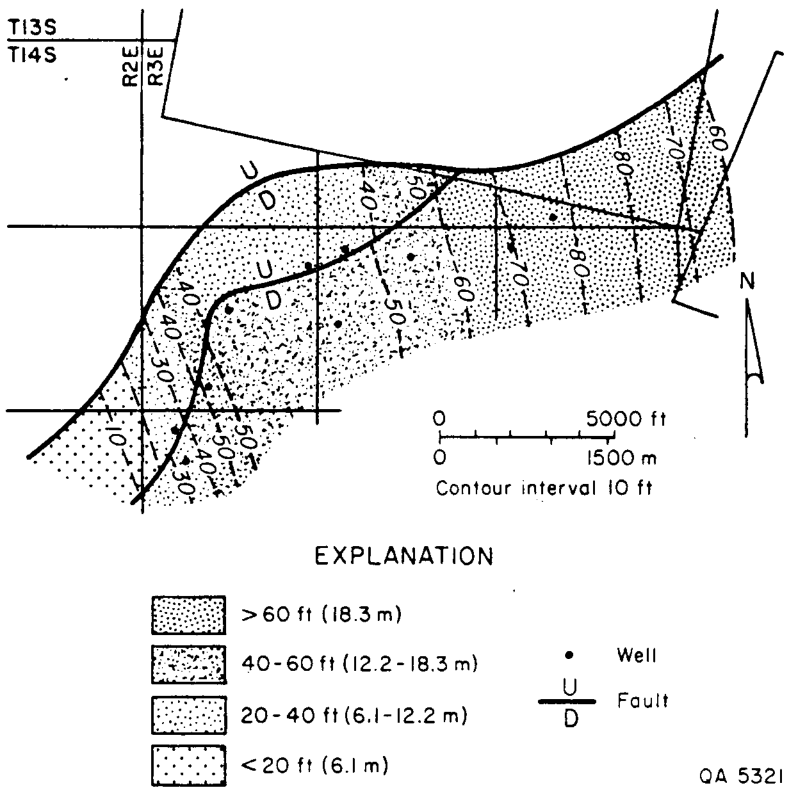


Figure 16. Sand isolith map, 13,700 sand. Net-sand thicknesses are greatest on the downthrown side of the minor fault.

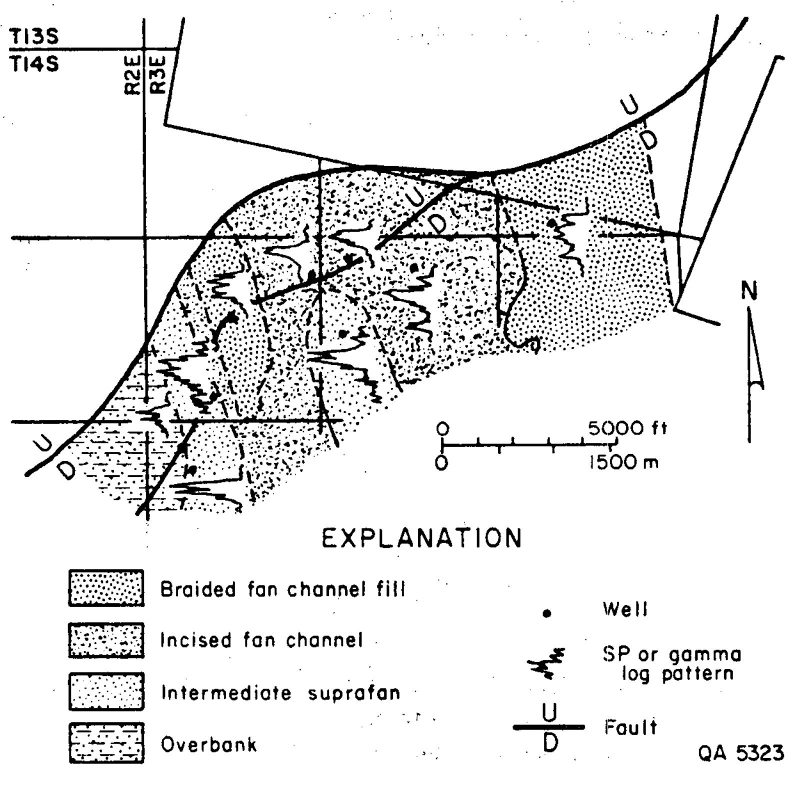


Figure 17. Log-pattern map for the 13,700 sand.

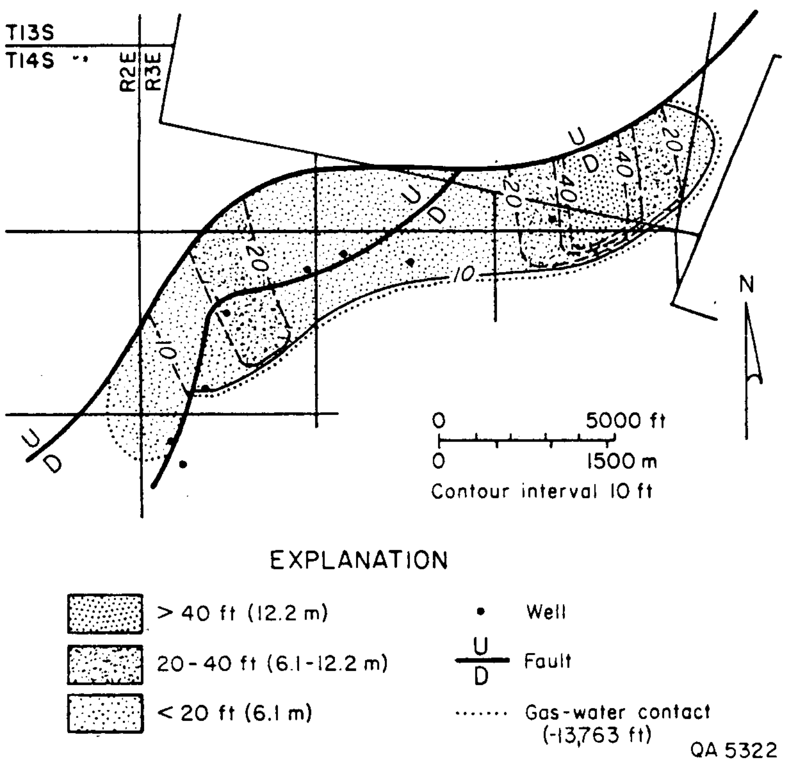


Figure 18. Net thickness of gas-bearing sand, 13,700 sand. Gas-water contact from Figure 14.

P. APPENDIX 16

LSU/GEOLOGICAL SURVEY PROSPECT FOR CO-PRODUCTION
TECHNICAL SPE PAPER

Z. BESSOUNI/D. ARCARO - LSU

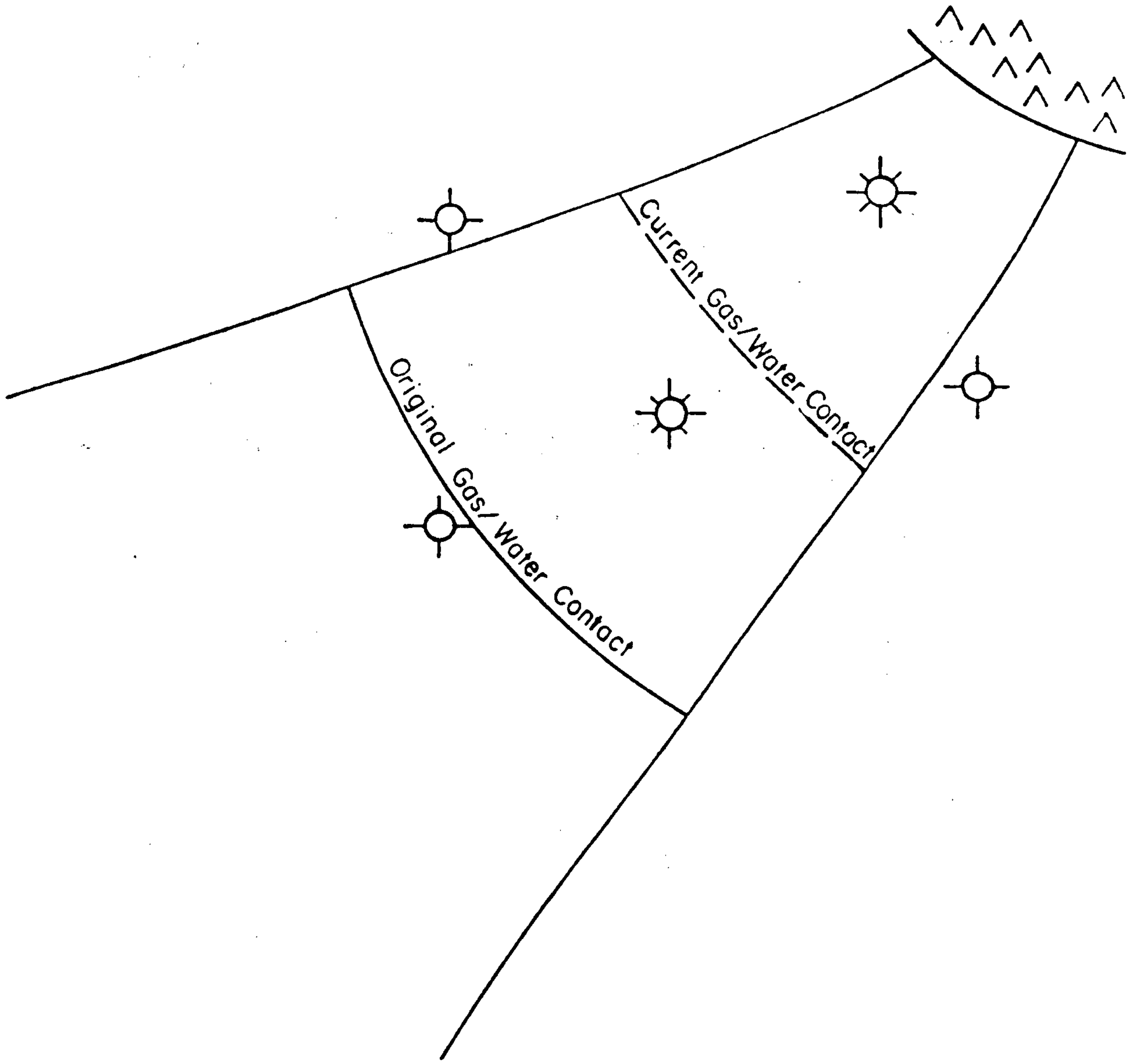
LOUISIANA STATE UNIVERSITY

LOUISIANA GEOLOGICAL SURVEY CONTRACT

ECONOMIC, ENGINEERING AND TECHNICAL SUPPORT FOR CO-PRODUCTION ACTIVITIES IN LOUISIANA

GRI CONTRACT NO. 5084-212-0997

CO-PRODUCTION TECHNIQUE



MAJOR OBJECTIVES

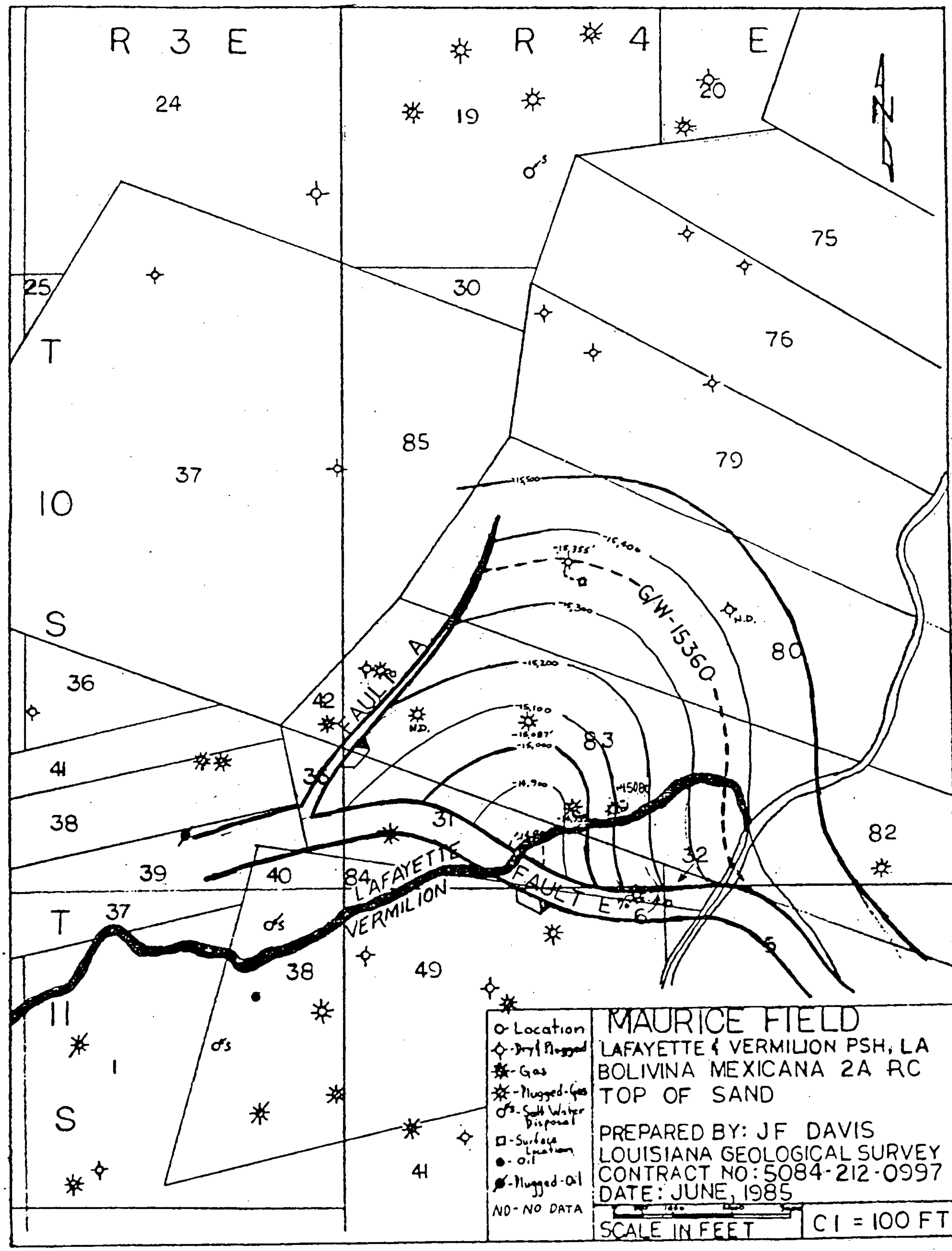
1. IDENTIFY CANDIDATE RESERVOIRS SUITED FOR CO-PRODUCTION FIELD TEST
2. CONDUCT DETAILED ENGINEERING AND ECONOMIC FEASIBILITY STUDIES OF CANDIDATE RESERVOIRS
3. DEVELOP CO-PRODUCTION TEST PLAN FOR POTENTIAL RESERVOIRS
4. ASSIST IN IMPLEMENTING AND MONITORING FIELD TESTS
5. EVALUATE AND REPORT RESULTS OF FIELD TESTS

SCREENING CRITERIA

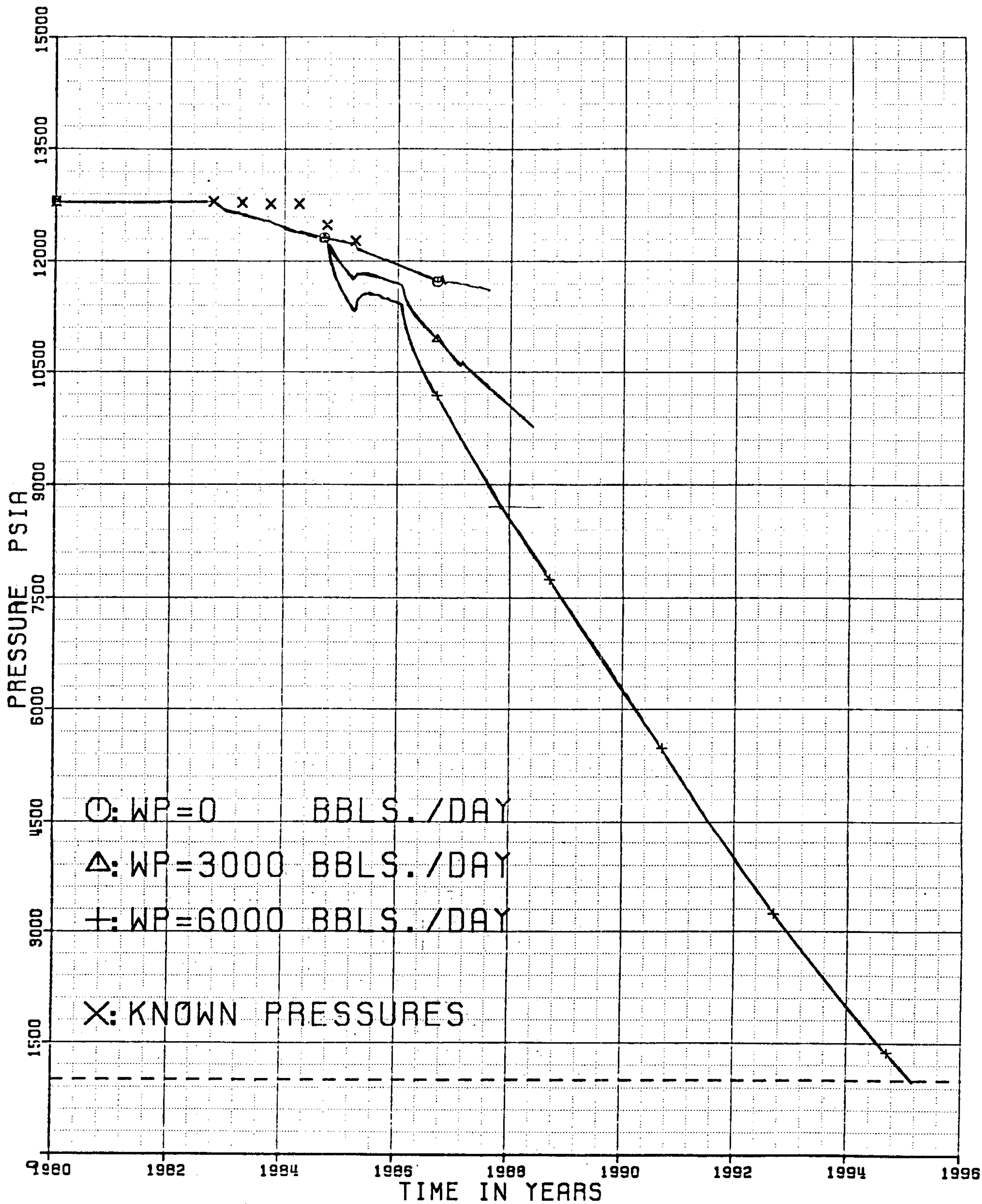
1. MODERATE WATER DRIVE GAS RESERVOIR
2. ADEQUATE GEOLOGICAL CONTROL
3. PRESSURE AND PRODUCTION HISTORY
4. PRIMARY PRODUCTION REMAINING
5. WATERED OUT WELLS FOR WATER PRODUCERS
6. SURFACE DISPOSAL SITE FREFERRED

MAJOR CO-PRODUCTION STUDIES

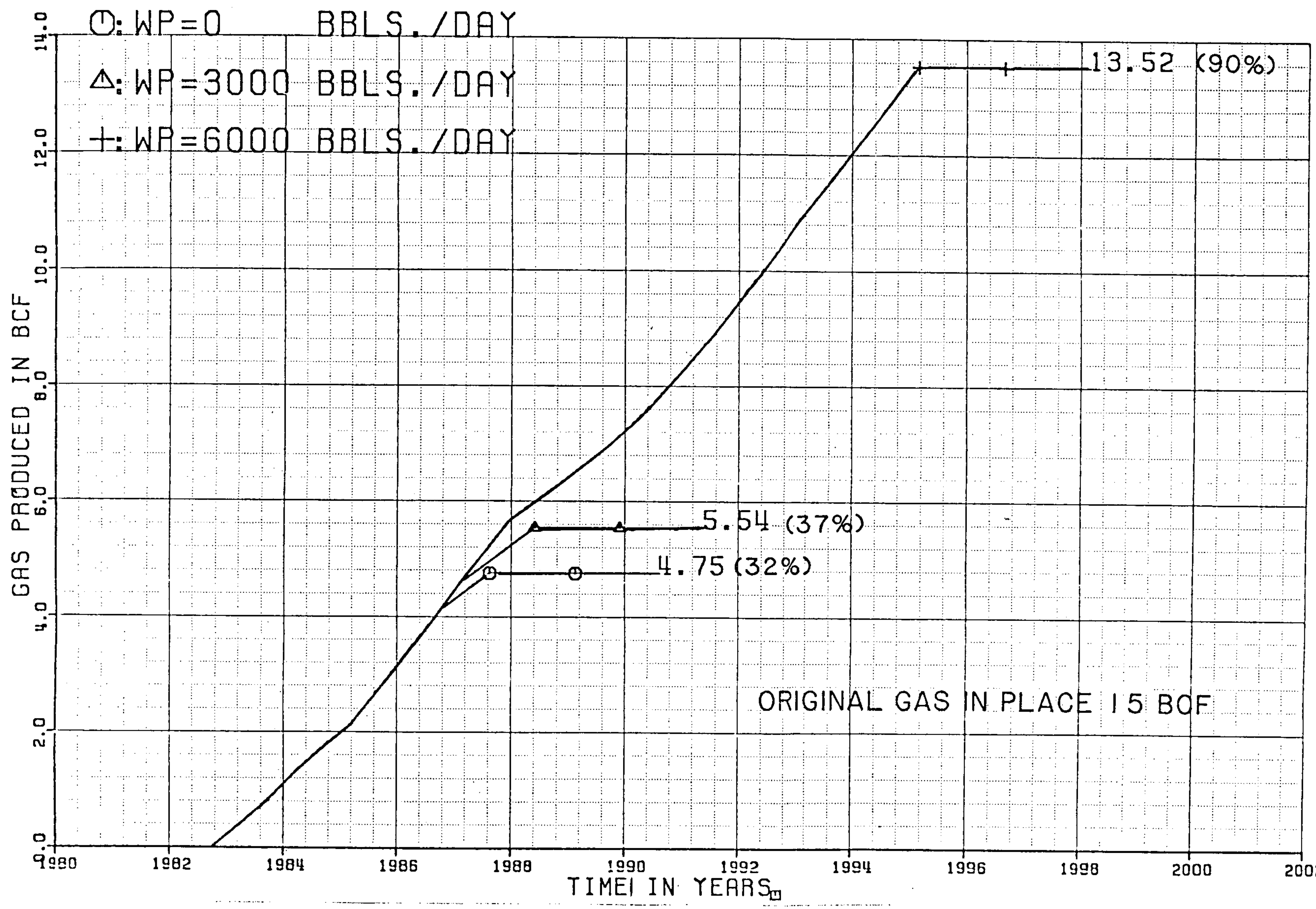
	COMPANY	RESERVOIR	STATUS
1.	Superior	Deep Lake	Analysis Completed Unsuitable Test Site
2.	Texaco	Lake Pelto	Analysis Completed Field Test Implementation on Hold
3.	Chevron	Eugene Island Block 350	Analysis Completed Field Test in 1986 Budget
4.	CNG	Ship Shoal Block 295	Analysis Completed Unsuitable Test Site
5.	Quintana	Garden City	Preliminary Analysis Completed
6.	Exchange Oil & Gas	N. Maurice Field	Preliminary Screening Completed
7.	Lea Exploration	Maurice Field	Preliminary Screening Completed

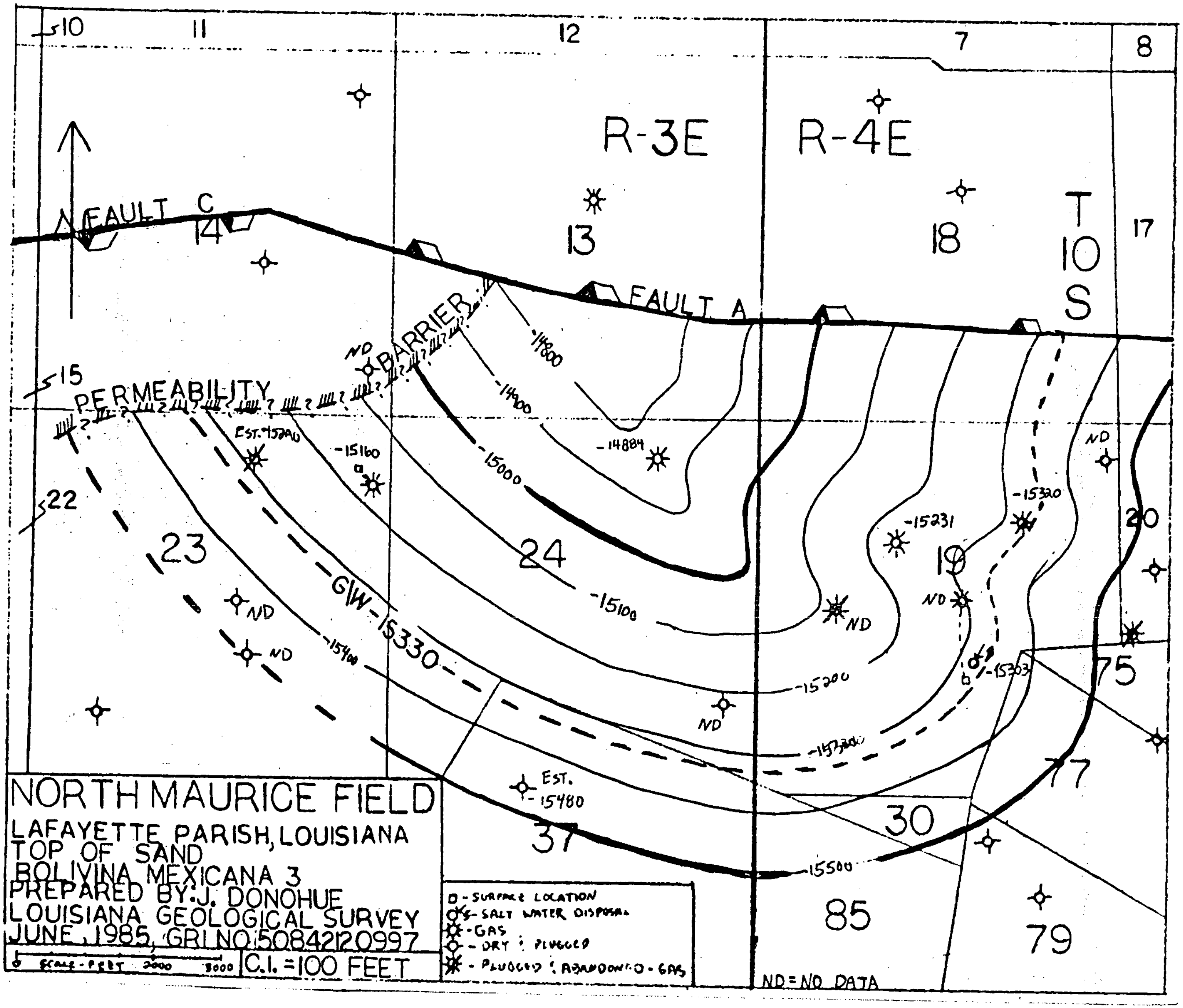


R 3 E
R 4 E
T 10 S
T 11 S
N
24
19
20
25
30
75
76
85
79
37
36
42
41
38
39
40
84
31
83
80
82
32
6
49
1
FAULT A
FAULT E
LAFAYETTE
VERMILION
G/W -15360
-15,500
-15,400
-15,355'
-15,300
-15,200
-15,100
-15,087'
-15,000
-14,900
15080
N.D.
MAURICE FIELD
LAFAYETTE & VERMILION PSH, LA
BOLIVINA MEXICANA 2A RC
TOP OF SAND
PREPARED BY: JF DAVIS
LOUISIANA GEOLOGICAL SURVEY
CONTRACT NO: 5084-212-0997
DATE: JUNE, 1985
Location
Dry & Plugged
Gas
Plugged-Gas
Salt Water Disposal
Surface Location
Oil
Plugged-Oil
ND - NO DATA
SCALE IN FEET
CI = 100 FT

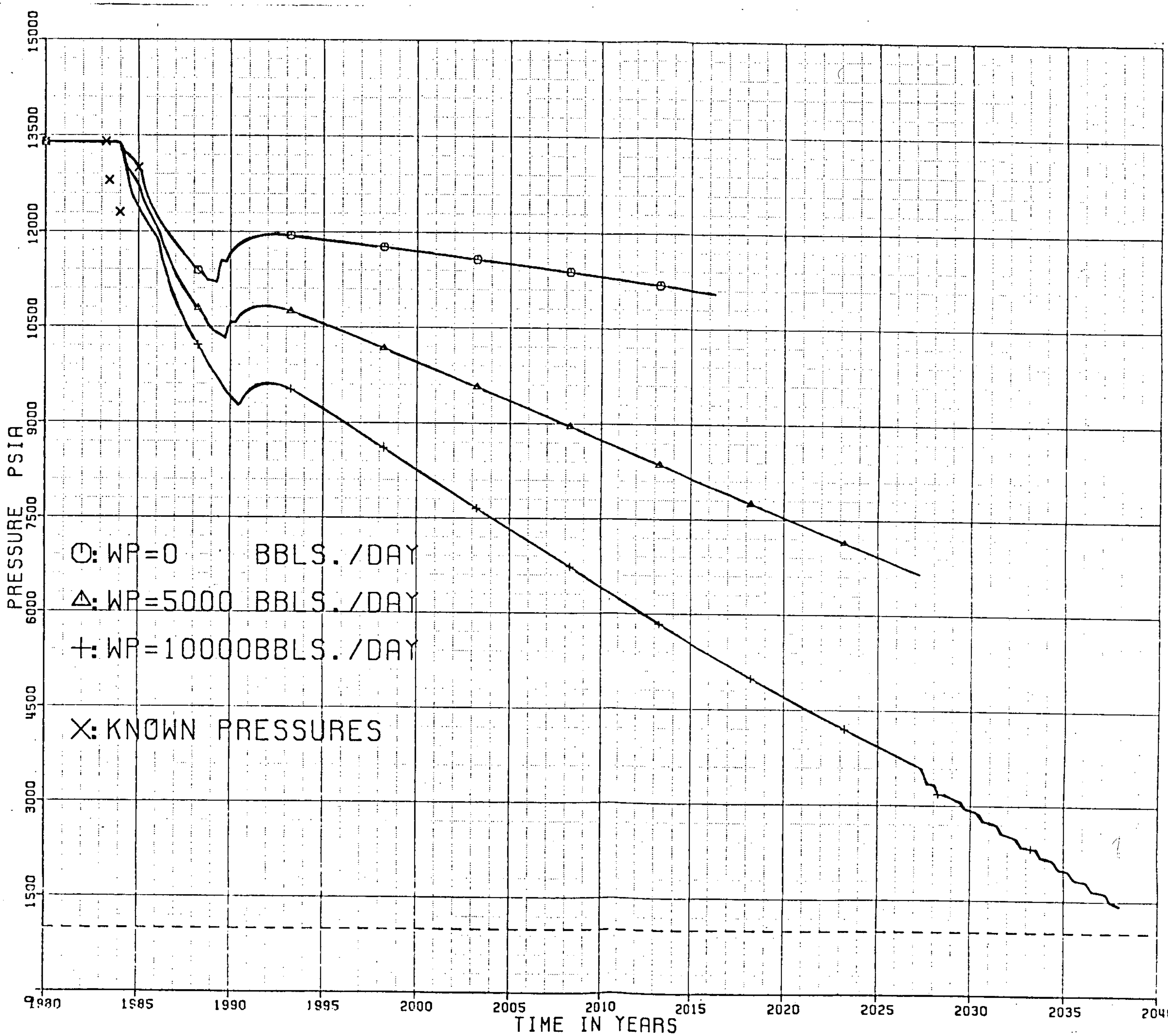


15000
13500
12000
10500
9000
7500
6000
4500
3000
1500
0
PRESSURE PSIA
1980
1982
1984
1986
1988
1990
1992
1994
1996
TIME IN YEARS
⊙: WP=0 BBLS./DAY
△: WP=3000 BBLS./DAY
+: WP=6000 BBLS./DAY
X: KNØWN PRESSURES

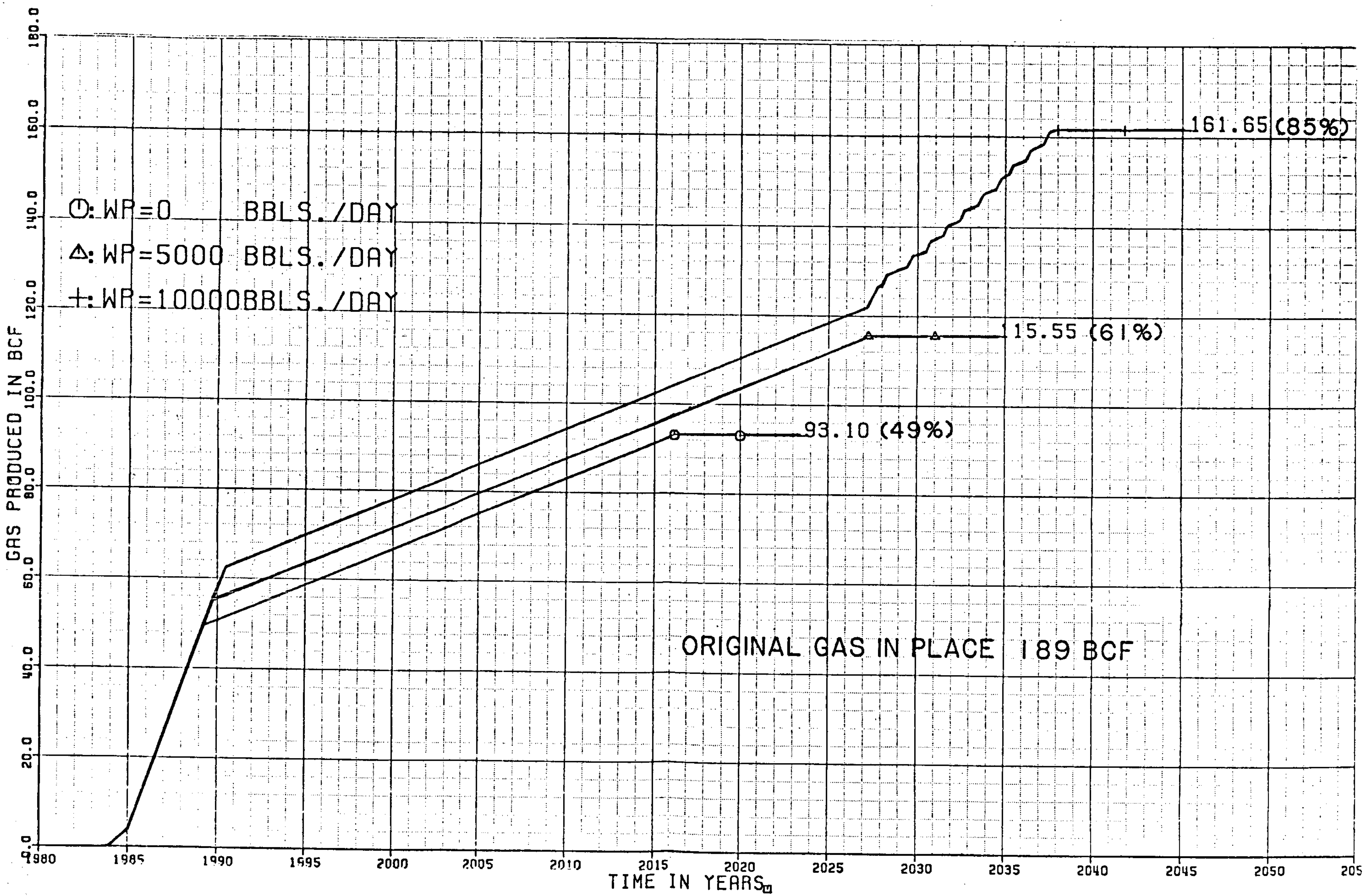

O: WP=0 BBLS./DAY
△: WP=3000 BBLS./DAY
+: WP=6000 BBLS./DAY
13.52 (90%)
5.54 (37%)
4.75 (32%)
ORIGINAL GAS IN PLACE 15 BCF
GAS PRODUCED IN BCF
0.0
2.0
4.0
6.0
8.0
10.0
12.0
14.0
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
TIME IN YEARS



10
11
12
7
8
R-3E
R-4E
FAULT C
14
13
18
T
10
S
17
FAULT A
BARRIER
PERMEABILITY
15
22
ND
EST. -15280
-15160
-14800
-14900
-14884
-15000
23
24
G/W -15330
-15100
ND
ND
-15400
-15231
19
ND
-15320
20
-15200
ND
-15303
75
-15300
77
EST. -15480
37
30
-15500
85
79
NORTH MAURICE FIELD
LAFAYETTE PARISH, LOUISIANA
TOP OF SAND
BOLIVINA MEXICANA 3
PREPARED BY: J. DONOHUE
LOUISIANA GEOLOGICAL SURVEY
JUNE, 1985, GRI NO. 50842120997
0 SCALE - FEET 2000 8000
C.I. = 100 FEET
- SURFACE LOCATION
- SALT WATER DISPOSAL
- GAS
- DRY & PLUGGED
- PLUGGED & ABANDONED - GAS
ND = NO DATA



PRESSURE PSIA
15000
13500
12000
10500
9000
7500
6000
4500
3000
1500
0
1980
1985
1990
1995
2000
2005
2010
2015
2020
2025
2030
2035
2040
TIME IN YEARS
O: WP=0 BBLS./DAY
△: WP=5000 BBLS./DAY
+: WP=10000BBLS./DAY
X: KNOWN PRESSURES



GAS PRODUCED IN BCF
TIME IN YEARS
O: WP=0 BBLS./DAY
Δ: WP=5000 BBLS./DAY
+: WP=10000BBLS./DAY
161.65 (85%)
115.55 (61%)
93.10 (49%)
ORIGINAL GAS IN PLACE 189 BCF
0.0
20.0
40.0
60.0
80.0
100.0
120.0
140.0
160.0
180.0
1980
1985
1990
1995
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050
205

SPE 14361

Society of Petroleum Engineers

The Technical and Economic Feasibility of Enhanced Gas Recovery in the Eugene Island Field Using Co–Production Technique

by D.P. Arcaro and Z. Bassiouni, Louisiana State University

Members SPE–AIME

This paper was prepared for presentation at the 60th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Las Vegas, NV September 22–25, 1985.

ABSTRACT

Conventional production in a water-drive gas reservoir terminates when the producing wells load up with water. This leaves high pressure by-passed gas in the watered out areas and in the gas cap updip of the watered out wells. Generally, recovery from water drive gas reservoirs is much less than that from depletion type gas reservoirs.

In the proposed co-production process, as the downdip wells begin to water out, they are converted to high-rate water producers while the updip gas wells maintain gas production. Utilization of the co-production process can enhance recovery in three ways. The production of water will lower reservoir pressure and more gas will be produced due to expansion. Water production will slow down the advance of the water front. Also, previous immobile gas in the swept zone might become mobile again as the pressure is lowered. The process is applicable in moderate to active water drive gas reservoirs with the greatest economic potential from those not yet watered out.

Basic material balance analysis, tank model simulation and a preliminary economic analysis demonstrated the technical and economic feasibility of the process for a case study, the Louisiana Gulf Coast Eugene Island Block 305, 10,300 foot sand gas reservoir. This study also shows that the co-production technique could result in a substantial increase in recovery efficiencies in many other water drive gas reservoirs under specific economic conditions.

INTRODUCTION

Water drive gas reservoirs generally have much lower recoveries than depletion drive reservoirs. In a water drive gas reservoir, the reservoir pressure is maintained by the encroaching water. The stronger the water drive the higher the reservoir pressure remains and the faster the water invades the field. Since residual gas saturation is independent of pressure, larger amounts of gas (residual gas) are trapped at the higher pressure than for lower stabilization pressure.

A technique of added recovery benefits in strong water drive gas reservoirs is the accelerated blowdown method (Ref. 1 & 2). In essence the concept is to outrun the water influx by producing gas at accelerated rates. Reservoir pressure is reduced before the aquifer can respond fully. However, usefullness of the process is limited in many cases. Deliverability controls due to sales contracts or production facilities may disallow high production rates. High permeability reservoirs show dampened efficiencies due to high water mobility. Resevoirs with a great deal of permeability variations show a reduced effectiveness of the method due to the uneven advancement of water. Water coning and well sanding problems may cause many operational problems. Oftentimes the scale of economic investment required to implement this process defers application.

The Louisiana State University Department of Petroleum Engineering and Center for Energy Studies (CES) are presently researching and promoting another enhanced gas recovery method refered to as the co-production technique. The research is sponsored by the Gas Research Institute (GRI), Chicago, Illinois. Various companies are actively paticipating by providing data and technical support to further research development.

CO-PRODUCTION TECHNIQUE

The co-production process is defined as the simultaneous production of gas and water. The initial attempts of enhanced gas recovery by co-production focused on the depressurization of a totally watered out reservoir by withdrawing large volumes of water (Ref. 3). This is technically feasible and economically applicable in some cases. In case of unfavorable gas relative permeability characteristics extremely large volumes of water must be removed to immobilize the gas. The cost involved to rework a shut in field and handle large amounts of two phase gas and water production at high water gas ratios might also be prohibitive.

The LSU study directs the application of the process to water drive gas reservoirs not yet totally watered out. The process requires converting downdip wells as they water out to water producers while gas production is maintained updip. The production of downdip water enhances recovery in three ways 1) slow down the advance of water front thus delaying the watering out of wells, 2) reduce reservior pressure so more gas can expand and be produced, and 3) reduce pressure in the swept zone so previously immobile gas can expand and might be produced. The updip gas wells can if warranted be produced at high rate thus incorporating the benefits of the accelerated blowdown method.

The implementation of the co-production technique during the primary life of a gas reservoir and using existing wells and infrastructure represents the greatest potential for its technical and economic feasibility.

RESERVOIR SELECTION

All types of water drive reservoirs are considered as candidates. However, adequate geological control and production history are necessary to define the reservoir shape and initial gas/water contact and for accurate technical evaluation of the field.

The ability to produce gas from an existing well with some primary production remaining is required. Also required are watered out wells to be converted to water producers. Prospects requiring the drilling of new wells are much less attractive from an economic viewpoint.

The availability of a surface disposal site for the produced water is preferable as it will enhance the economic potential of the prospect reservoir. Selection criteria might be modified in the future as more experience is gained.

Several candidate study fields were selected while working in conjunction with various oil and gas companies. Chevron suggested the Eugene Island Block 305, 10,300 foot sand reservoir as a potential reservoir for the application of the co-production process. It is a moderate water drive gas-condensate reservoir which was put on production in late 1979 with six gas producing wells. Presently, three downdip wells are watered out with a fourth developing an increasing water cut. There is good geological control to support the field description. The reservoir is located in an offshore area so surface disposal of treated water is possible. As of January 1, 1985 142 BCF of gas out of an original estimated 274 BCF of gas has been produced for a 52% recovery. Strong technical support data, core tests, fluid analysis and pressure measurements enable this reservoir to meet all the selection criteria previously mentioned.

RESERVOIR STUDY

Various production schemes must be considered to determine the maximum possible ultimate recovery. The first case to be examined is the conventional production base case, where the reservoir is allowed to continue as is, without any water producers, until watering out. Under the co-production process the choices are 1,2 or 3 water wells on. Each additional water well may increase recovery but it will also increase costs. This becomes an economic decision once the technical evaluation to estimate future recovery for each case is complete.

The reservoir description, all production data as well as all previous engineering and geological evaluations are reviewed first. Volumetric analysis could be used to determine and/or confirm current gas water contact. Next the possible water producers are analyzed for estimated maximum water production by artifical lift. A simple material balance approach is then used to estimate the range and magnitude of predicted recoveries for the conventional field production method and for the co-production method. With refinement this method may give reasonable conclusions without further analysis. For further study a two or three dimensional simulator can be used for a complete evaluation of the reservoir and its future performance. The study concludes with an economic feasibility of the project based on estimated costs and predicted recovery.

RESERVOIR DESCRIPTION AND PROPERTIES

Eugene Island Block 305 in the 10,300 foot sand is a moderate water drive gas condensate reserovir. It is located approximately 100 miles off the Louisiana shore in 240 feet of water. A structure map is shown in Fig. 1. Six wells were completed in this sand in 1979. Original gas in place is estimated to be 274 BCF for a reservoir volume of 135,730 acre feet. 142 BCF of gas and 4.4 MM STB of condensate have been produced through December 1984.

Because of the large size of the reservoir detailed fluid and core analyses were justified during the exploration phase. Average reserovir properties have been carefully evaluated and are summarized in Table 1. Laboratory tests included bulk compressibility measurements, relative permeability curves, residual gas saturation tests, PVT analysis and conventional core analysis. Condensate recovery during depletion was also tested. This information aided substantially in the modeling process.

The reservoir was found to be very heterogeneous such variations in permeability and porosity allow for uneven sweep and uneven advancement of water. Approximately 5.5 years of gas, water and oil production data is available. Numerous static bottomhole pressure measurements have been made. Gas re-cycling for additional condensate recovery during the early life of the reservoir was considered but determined uneconomical.

All wells were completed and tested in 1979. 3½" or 4" tubing was installed in all wells. Wells B-1 and B-10 have a short segment of 2 7/8" tubing just above the perforation. Average well depth is 11,048 feet. All wells tested at rates greater than 20 MMCFD. None are gravel packed. Well B-10 was shut-in in early 1983 due to high water cut and workover problems. Well B-7 watered out three months afterwards. Well B-2, even though updip of Well B-3, showed early water production. This could be due to perforation position and uneven water advancement. Well B-3 is presently showing an increasing water cut and Well B-2 has watered out.

VOLUMETRIC ANALYSIS

Simple volumetric calculations are a good supportive evaluation that can be used to confirm basic data such as the size of the reserovir and location of the original gas-water contact. Simultaneous equations are generated to express reservoir voidage volumes. Production data through April 1983 was used. At that time the most downdip well is known to water out and a new gas/water contact can be assumed at that level.

Assuming that reservoir pressure is fully maintained in the invaded portion of the reservoir, the total gas produced can be expressed as:

$$G_p = G_{p1} + G_{p2}$$
$$= \phi h\ \{\text{Area}_1\ (1-S_w)(b_{gi} - B_g) + \text{Area}_2\ (1-S_w-S_{gr})b_{gi}\} \quad (1.a)$$

$$\text{Area}_{total} = \text{Area}_1 + \text{Area}_2 \quad (1.b)$$

Volumetric evaluation confirmed the original estimated reservoir size and initial gas-water contact.

WATER PRODUCTION ESTIMATES

In order to anticipate water producing ability as well as provide data for the computer model, estimates of well gas lift capacity must be prepared. Gas lift estimates were made on a LSU program using Hagedorn and Brown two phase flow correlations (Ref. 4). It is estimated that water can be produced at a rate of 2,000 STBW/D.

MATERIAL BALANCE APPROACH

The use of the basic material balance equation can give a good approximation to the possible recoveries for the conventional case and the co-production case. For a gas reservoir the MBE can be expressed as:

$$G_p B_g = G(B_g - B_{gi}) + W_e - W_p B_w \quad (2)$$

This expression is used to represent different co-production schemes by varing W_p according to the number of water wells on.

Figure 2 shows the predicted pressure history for different production schemes. The $W_p = 0$ case represents conventional production scheme. As can be seen, reservoir pressure is lowered by water production. The more water is produced the lower the pressure that can be attained and in turn the longer the reservoir life and the higher the recovery. This cease to be true, however, beyond a water production rate of 10,000 Bbls/day. In this case the reservoir pressure reaches the chosen limiting value of 1500 psia much faster to the detriment of ultimate recovery. Table 2 lists the ultimate recovery as a function of rate of water withdrawal. It should be noted that this approach does not take into consideration the actual reservoir geometry and wells locations.

TANK MODEL

History matching and prediction of pressures and gas production are generated using CHEVRON'S "simple gas system" simulator. It is a layered tank model based on the material balance equation. Twelve layers were used to describe the reservoir as shown in Fig. 3. The watering out elevation of Well B-2 was adjusted to reflect its early watering out. All other well elevations were set to water out at 3/4 of their perforations. The Schilthuis Steady-State Method was found to describe best the water influx. The produced gas each year per well was inputed as a time dependent production schedule over the known history. Future performance of each well was controlled by deliverability equations. Vertical tubing description and early well test data was inputed for each well. Flow capacities for future well deliverability were then computed by the Cullender and Smith method. The history match run used 1979 well test data and the co-production used 1984 well test data to calculate deliverability. The Cullender and Smith values were considered up to two years before the wells would water out. Once this point is reached the rates are reduced, to portray more accurately the reduction in gas rates due to the watering out process. The reduction is done using known gas/water ratios of wells in the same reservoir. The gas deviation factors were calculated from inputed gas analysis. The reservoir porosity, connate water saturation, reservoir pressure and temperature used in the program were all actual measured values. The remaining parameters, K, water influx constant and C_f, formation compressibility were left as unknowns to be adjusted to create the history match.

HISTORY MATCH

A K value of 3.9 bbls/day/psi was found to give an accurate history match for a formation compressibility of 20to 25 micro-sips. The compressibility values derived from the history matching adjustment were found to be within the ranges of the true measured formation compressibilities and considered acceptable. Several runs were made to check the sensitivity of the history match to values of C_f and K. These runs confirmed the uniqueness of the history match. The history match was continued into the future as a base run for conventional production as shown in Fig. 4.

CO-PRODUCTION MODELING

The tank model program does not handle water production. In order to model the effective water encroachment the aquifer strength is reduced, which is essentially what co-production does.

For each 1000 psia drop range, the actual water influx rate is first calculated for a K of 3.9 bbls/day/psi. Then the water production rate is subtracted from actual water influx to determine the effective water influx. The new reduced water influx rate is divided by the pressure drop to find the "effective" K. The new K is then used in the detailed co-production run. The greatest recovery was found for a total water production rate of 6,000 Bbls/day which requires the use of three "water" wells.

Figures 5,6 and 7 show the predicted pressure and production histories for both conventional and co-production schemes. Under the conventional recovery production scheme the reservoir is estimated to water out by 1988 with a 62% recovery. Co-production allows the reservoir to continue producing until 1995 before watering out for a 82.6% recovery. When the economic limit of co-production is reached it is possible to convert back to conventional production. That is turn off the water wells and collect the remaining updip gas production at the highest rates possible.

ECONOMIC ANALYSIS

In order to compare the profitability of the co-production technique to conventional production, economic runs were made using POGO (Profitability of Oil and Gas Opportunities) economic model. Representative economic parameters are used. These parameters are listed in Table 3.

Results of the economic evaluation for conventional and co-production cases are summarized in Table 4. Present value cash flow before and after income tax and project life are given for gas prices ranging from \$0.50 to \$5.00/MCF.

Figure 8 illustrates the present value cash flow before income tax as a function of gas price for conventional and co-production cases. It should be also noted that payout time for all options considered is less than six months. The present value cash flow generated by co-production is about twice that generated using conventional production at any gas price in the range 1.50 to \$5.00/MCF. At a gas price of \$2.75/MCF the incremental present value cash flow before income tax gained by using co-production is of about \$50 million. The total capital investment is only \$1.5 million.

CONCLUSIONS

1. The co-production technique presents a viable technical method aimed at enhancing recovery from water drive gas reservoirs.

2. The feasibility of the co-production technique in an actual case is demonstrated by the technical analyses of Eugene Island Block 305, 10,300 foot sand water drive gas reservoir. The predicted recovery for the co-production case is 83% compared to only 62% for the conventional production approach. This represent an increase of 56 BCF.

3. The economic analysis shows the co-production technique to be a very attractive option of producing this reservoir. It is also anticipated that co-production can be economically feasible as well in many other water drive gas reservoirs under specific economic conditions.

NOMENCLATURE

G = original gas in place, SCF

G_p = cumulative gas production at time t, SCF

G_{p1} = gas produced by expansion, SCF

G_{p2} = gas produced by water drive, SCF

B_{g_i} = original gas volume factor, RB/SCF (b_{g_i} = scf/rb)

B_g = gas volume factor at time t, RB/SCF (b_g = scf/rb)

B_w = water volume factor

W_e = cumulative water influx at time t, res. bbl.

W_p = cumulative water produced by co-production, res. bbls.

$Area_1$ = uninvaded reservoir area, acre

$Area_2$ = invaded reservoir area, acre

$Area_{Total}$ = total reservoir area, acre

S_w = connate water saturation, fraction

ϕ = porosity, fraction

h = reservoir thickness, ft

S_{gr} = residual gas saturation, fraction

ACKNOWLEDGMENT

The authors gratefully acknowledge the engineering assistance from the Chevron staff. The release of proprietary data by Chevron and Mobil is also appreciated. The contribution of Don Remson and Keith Halford of LSU was essential to the completion of this study. Research presented by this paper is sponsored by the Gas Research Institute. The economic program POGO used in this study was developed by PSI Energy Software.

REFERENCES

1. Lates, J.L., Chiang, C.P., Ressen, R.H., and Brady, M.M., "Accelerated Blowdown of a Strong Water-Drive Gas Reservoir", J. Pet. Tech. (December, 1977) 1533-1538.

2. Brinkman, F.P., "Increased Gas Recovery from a Moderate Water Drive Reservoir", J. Pet. Tech. (December, 1981) 2475-2480).

3. Gregory, A.R., Lion, Z.S., Reed, R.S., Morton, R.A., and Rogers, L.A., "Watered-Out Gas Reservoirs Profitable Via Enhanced Recovery", Oil and Gas Journal (March, 1983), 35-60.

4. Hagedorn, A.R. and Brown, K.E., "Experimental Study of Pressure Gradients Occurring During Continuous Two Phase Flow in Small Diameter Vertical Conduits", J. Pet. Tech. (April, 1975) 475-484.

TABLE 1

Average Reservoir Properties, Eugene Island Block 305, 10,300' sand

Original Reservoir Pressure:	8143 psia
Current Reservoir Pressure:	≈4800, psia
Acre-ft:	135,730 ac-ft.
Original Gas in Place:	274 BCF
Porosity:	24.6%
S_{wi}; connate water saturation:	44.9%
Gas Gravity:	.729
Residual Gas Saturation:	30.0%
Condensate Yield in 1980:	42 bbl/MMCF
Condensate Yield in 1984:	20 bbls/MMCF
API gravity:	47.9°
Reservoir Temperature:	195°F
Reservoir Datum (subsea):	11,180 ft.

TABLE 2

Recovery Predictions Using The Basic Material Balance Equation

Rate of Water Production W_p BBLS/D	Ultimate* Recovery, BCF	% Recovery*
0	170	62
2,500	179	65
5,000	188	69
7,500	224	82
10,000	229	84
12,500	224	82

* For a terminal pressure of 1500 psia

TABLE 3

Summary of Economic Parameters Used in the Evaluation

- Gas Price: Range of $0.5 to $5/MCF
- Oil Price: $20/Bbl (gas and oil prices were held constant during the entire life of the project)
- Capital Investments: none, conventional prediction; $1,535,220, co-production
- Operating Expenses: $2,000/day/well
- Royalty: 1/6 (off-shore Federal Lease)
- Windfall Profit Tax: New (Tier III), $17/STB base price
- Discount Rate: 15%
- Federal Income Tax: 46%
- Investment Tax Credit: 10% of tangible expenses
- Deductible Expenses: 80% of intangible expenses
- Depreciation: Accelerated Cost Recovery Schedule, 20% of intangibles plus 95% of tangibles

TABLE 4

ECONOMIC RESULTS

Gas Price ($/MCF)	PVCFBIT Conv (MM$)	PVCFBIT Co-Prod (MM$)	PVCFAIT Conv (MM$)	PVCFAIT Co-Prod (MM$)	PROJECT LIFE Conv (YR)	PROJECT LIFE Co-Prod (YR)
.50	3.6935	3.9427	1.9945	2.0632	1.5	2.75
1.00	7.7936	12.5778	4.2085	6.7538	2.25	5.17
1.50	12.5632	22.8321	6.7841	12.2911	3.0	6.83
2.00	17.7139	33.7985	9.5655	18.2130	3.0	8.33
2.50	22.8648	45.0604	12.3470	24.2944	3.0	8.83
2.75	25.4402	50.7393	13.7377	27.3610	3.0	9.00
3.00	28.0156	56.4186	15.1284	30.4278	3.0	9.17
3.50	33.1665	67.8104	17.9099	36.5794	3.0	9.42
4.00	38.3173	79.1699	20.6914	42.7136	3.0	10.00
4.50	43.4682	90.6467	23.4728	48.9111	3.0	10.00
5.00	48.6191	102.1235	26.2543	55.1086	3.0	10.00

PVCFBIT = PRESENT VALUE CASH FLOW BEFORE INCOME TAX

PVCFAIT = PRESENT VALUE CASH FLOW AFTER INCOME TAX

PROJECT LIFE = POINT IN TIME WHERE OPERATING EXPENSES BECOME GREATER THAN OPERATING INCOME AND ECONOMIC ANALYSIS IS HALTED.

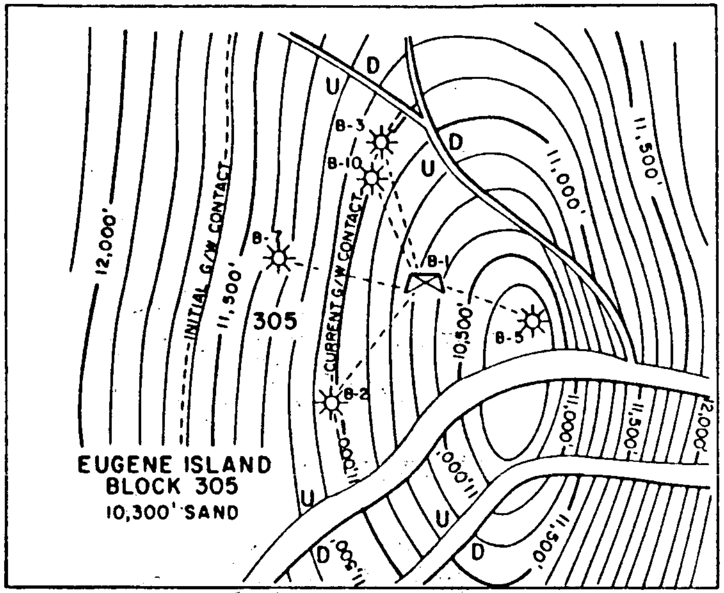


Fig. 1. Structure Map of Eugene Island Block 305, 10,300' sand Gas Reservoir

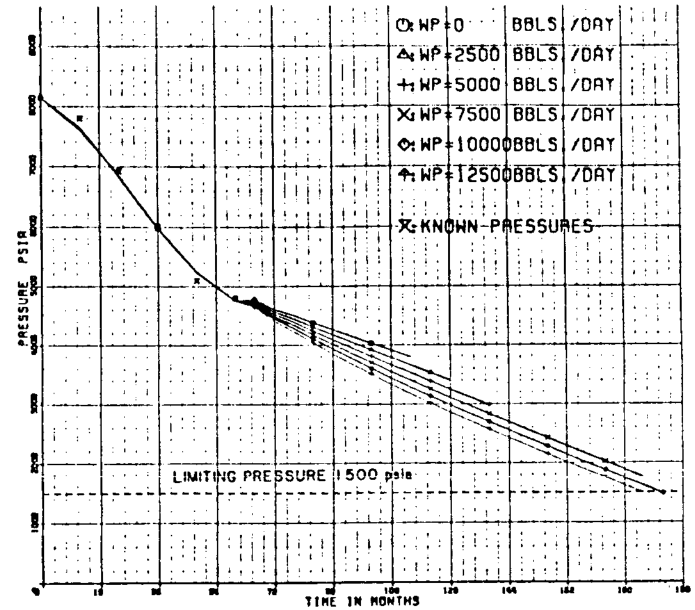


Fig. 2. Predicted Pressure History and Reservoir Life Using Basic Material Balance Equation

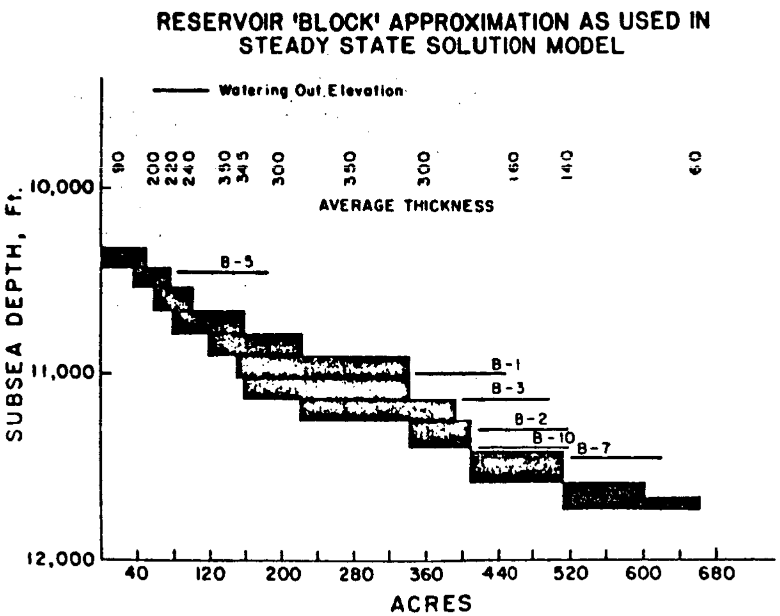


Fig. 3. Reservoir Block Representation Used in the Tank Model

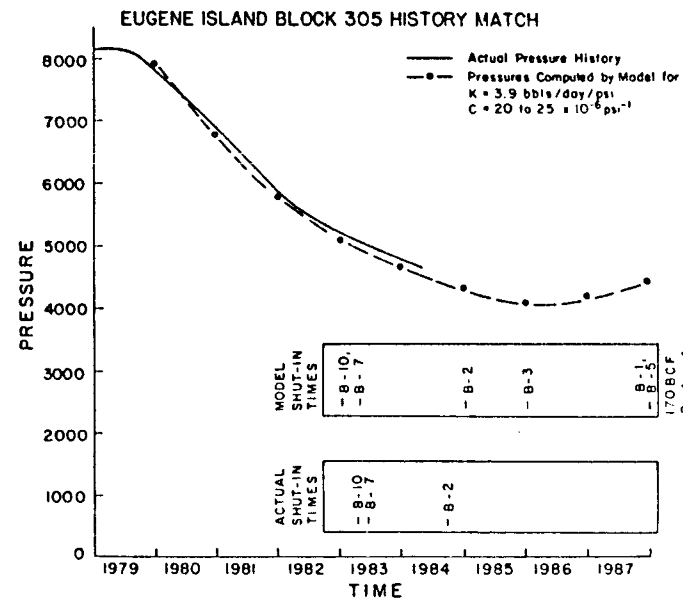


Fig. 4. Pressure History Match and Predicted Pressures for Conventional Production

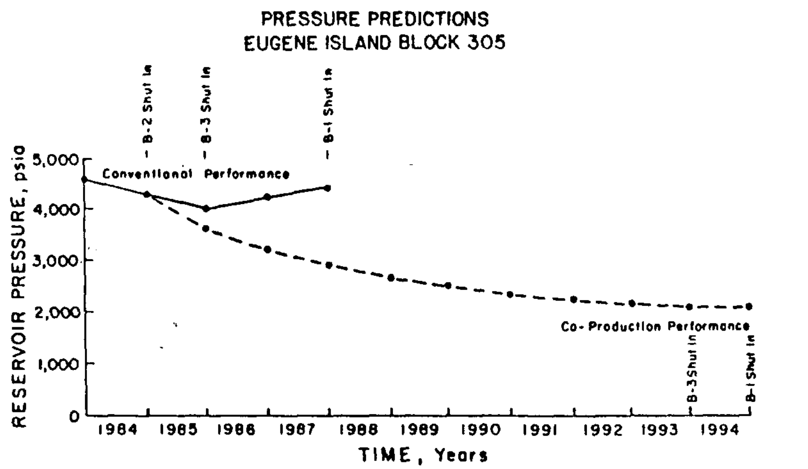


Fig. 5. Pressure History and Reservoir Life Predicted for Conventional and Co-Production Cases

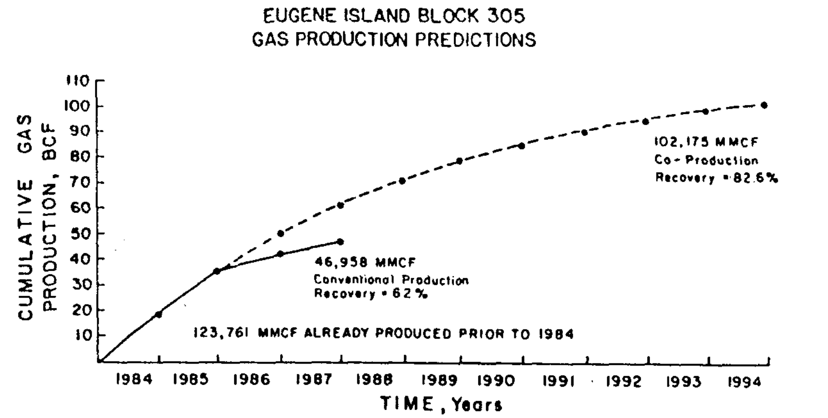


Fig. 6. Cummulative Gas Production and Ultimate Recovery Predicted for Conventional and Co-Production Cases

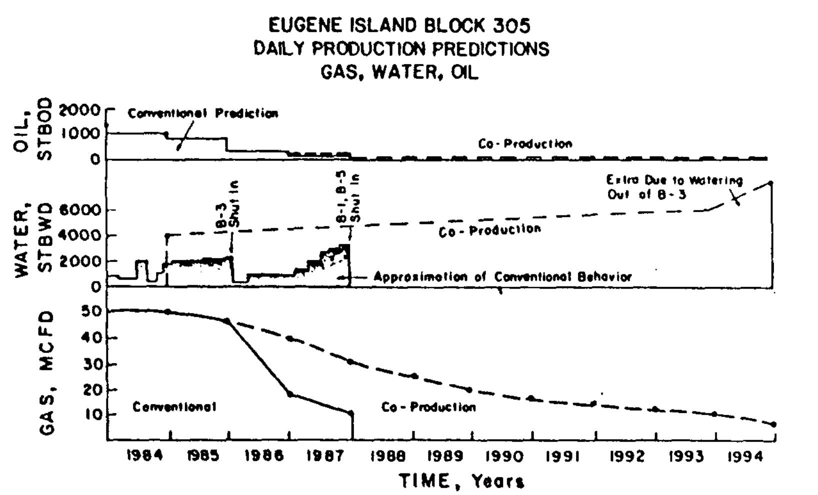


Fig. 7. Daily Gas, Oil and Water Production Rates Predicted for Conventional and Co-Production Cases

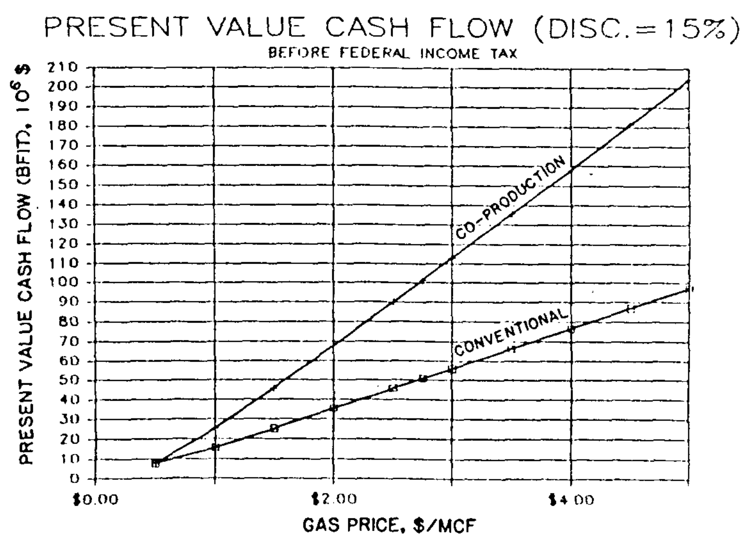


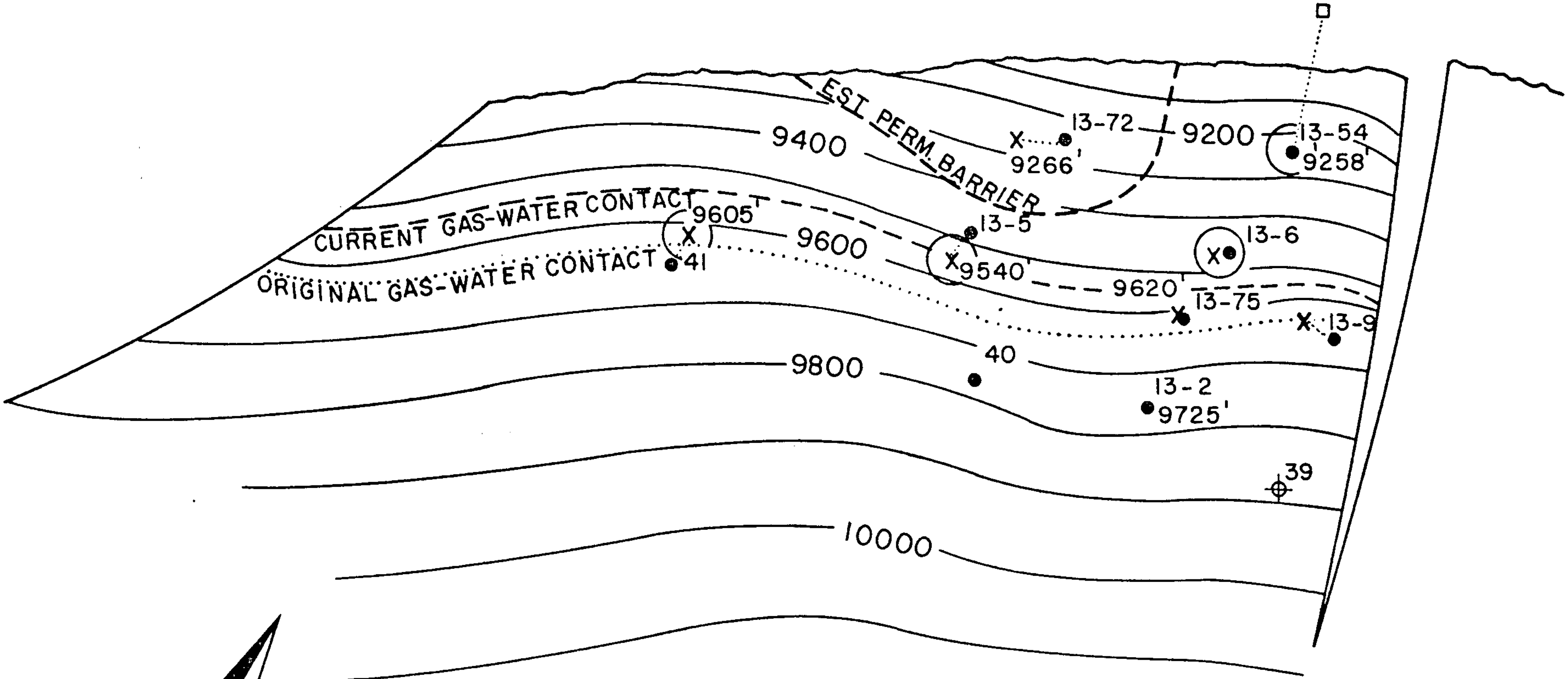
Fig. 8. Present Value Cash Flow Before Federal Income Tax as a Function of Gas Price for Conventional and Co-Production Cases

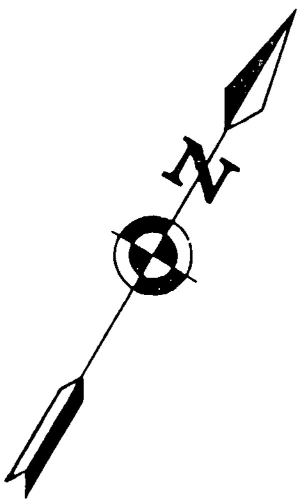
TECHNICAL AND ECONOMICAL

FEASIBILITY OF

ENHANCED GAS RECOVERY

IN THE LAKE PELTO 9600′ SAND





LAKE PELTO FIELD
9600–FT. SAND, SEGMENT 600

STRUCTURE MAP

ENGR. M. L. P. DATE 10/83

0 500' 1000'

SCALE

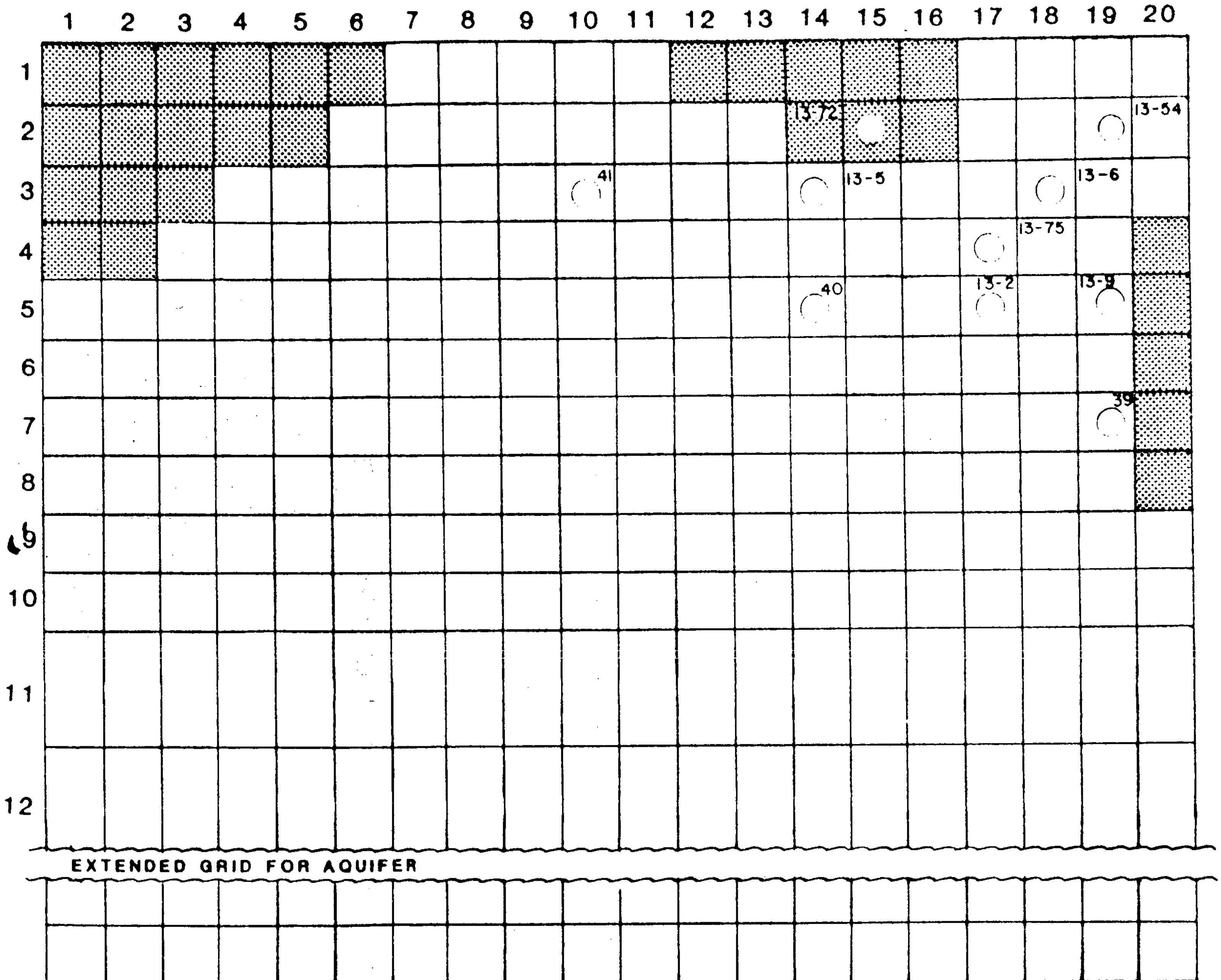
SUMMARY OF RESERVOIR PROPERTIES FOR THE LAKE PELTO 9600′ SAND

Reservoir Area	38 acres
Average Thickness	41 feet
Total Volume	1558 ac-ft
Porosity	31%
S_{wi}	15%
Gas Gravity	.65
Residual Gas Saturation (Imbibition)	30% (of pore volume)
Reservoir Temp.	190° F
Permeability, K	1100 md
$B_w = 1.028$	$B_g = 3.97 \times 10^{-3}$ ft^3/SCF
$\mu_w = .34$ cp	$\mu_g = .02219$ cp
Condensate (initially)	25.7 bbls/MMCF

HISTORICAL PRODUCTION
WELL 13-5

DATE	MONTHLY GAS PRODUCTION MCF	REPORTED MONTHLY WATER PRODUCTION STBW	REVISED MONTHLY WATER PRODUCTION STBW	MONTHLY OIL STBO
4-71	65,468*1			619
5-71	103,906			2258
6-71	92,584			2868
7-71	111,776			3122
8-71	148,958			3566
9-71	127,980			4616
10-71	175,776	6800	6800	6800
11-71	146,233	2736	7000	2736
12-71	112,267	2284	8060	2284
1-72	19,558	312	2030	312
TOTAL	1,104,506	12,132	23,890	29,181

*1 includes production from unit 13-Well 41



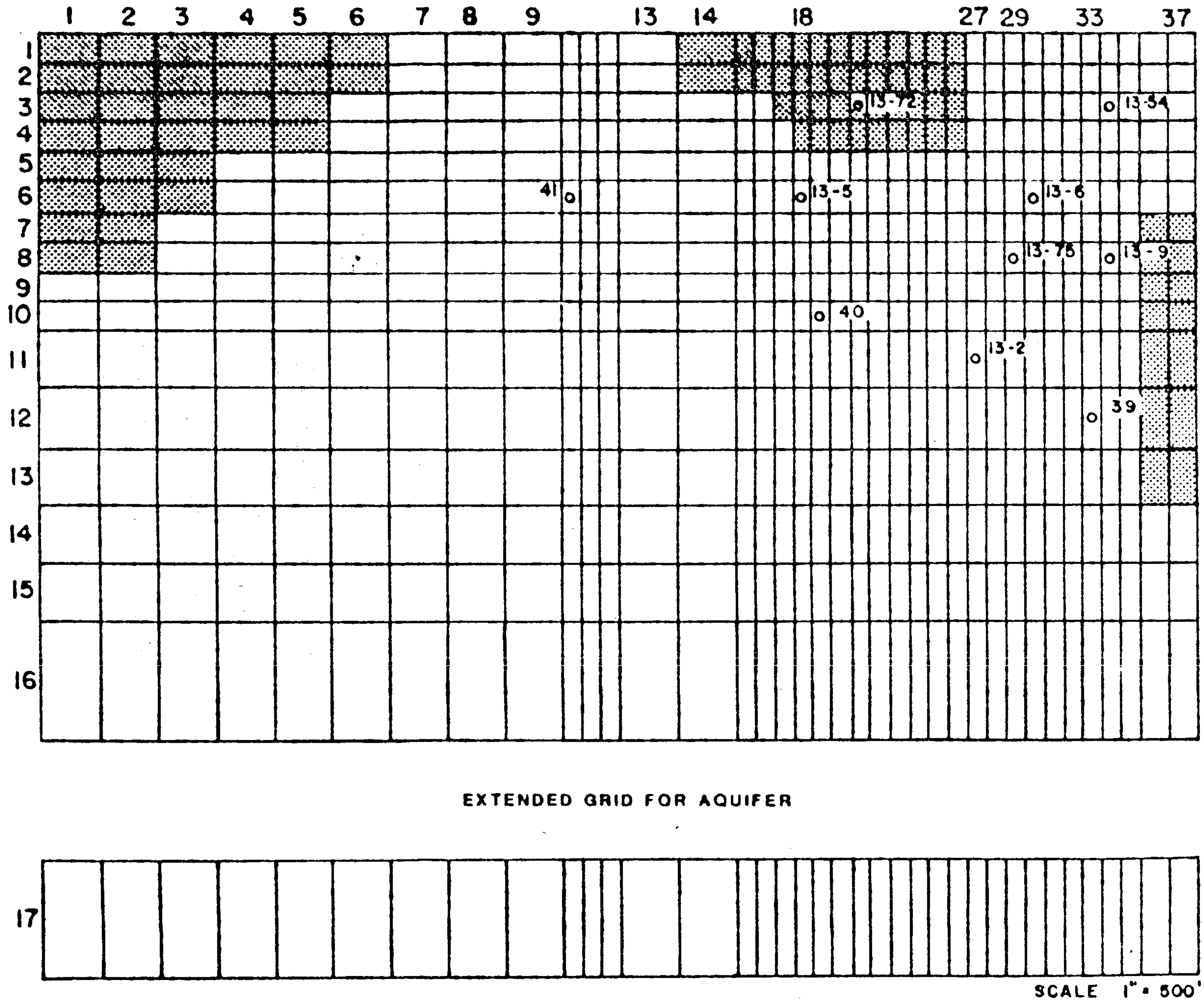
GRID SYSTEM FOR MODEL ONE
LSU STUDY - LAKE PELTO

FIGURE 6

SUMMARY OF RESULTS FOR MODEL ONE

Case	Cumulative Future Production
Base Case 13-54 on only No gas lift	Probable watering out in 6 months 0.9 BCF of production 41% total recovery
Case 2 13-54 gas producer 13-6 water producer	Gas lift for 7 years 2.9 BCF of production 82% total recovery
Case 3 15-54 gas producer 13-6 water producer 13-5 water producer	Gas lift for 6 years 2.9 BCF of production 82% total recovery
Case 4 13-54 gas producer 13-6 water producer 13-5 water producer 13-41 water producer	Gas lift for 4 years 3.1 BCF of production 85% total recovery

FIGURE 11

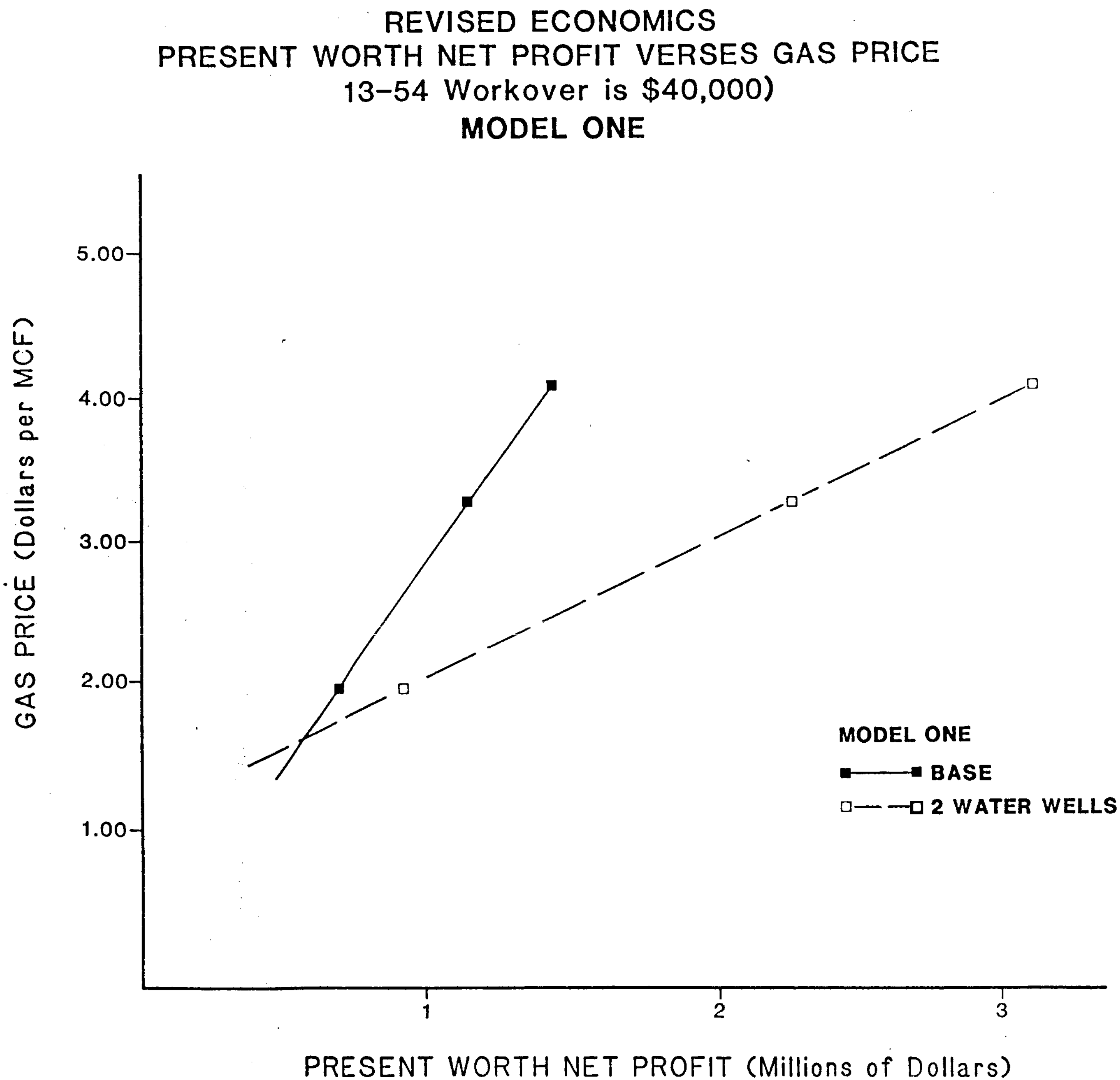


GRID SYSTEM FOR MODEL TWO
LSU STUDY - LAKE PELTO

SUMMARY OF RESULTS FOR MODEL TWO

Case	Cumulative Future Production
Base Case 13-54 on only No gas lift	Probable watering out in 8-9 months 1.5 BCF of production maximum 53% recovery
Case 2 13-54 gas producer 13-6 water producer	Gas lift for 9-10 months 1.68 BCF of production 57% recovery
Case 3 13-54 gas producer 13-6 water producer 13-5 water producer	Gas lift for 9-10 months 2.12 BCF of production 65% recovery
Case 4 13-54 gas producer 13-6 water producer 13-5 water producer 13-41 water producer	Gas lift for 9-10 months 2.15 BCF of production 65% recovery

FIGURE 20B



REVISED ECONOMICS
PRESENT WORTH NET PROFIT VERSES GAS PRICE
13-54 Workover is $40,000)
MODEL ONE
GAS PRICE (Dollars per MCF)
5.00
4.00
3.00
2.00
1.00
1
2
3
PRESENT WORTH NET PROFIT (Millions of Dollars)
MODEL ONE
BASE
2 WATER WELLS

REVISED ECONOMICS
PRESENT WORTH NET PROFIT VERSES GAS PRICE
(13-54 Workover is $40,000)
MODEL TWO

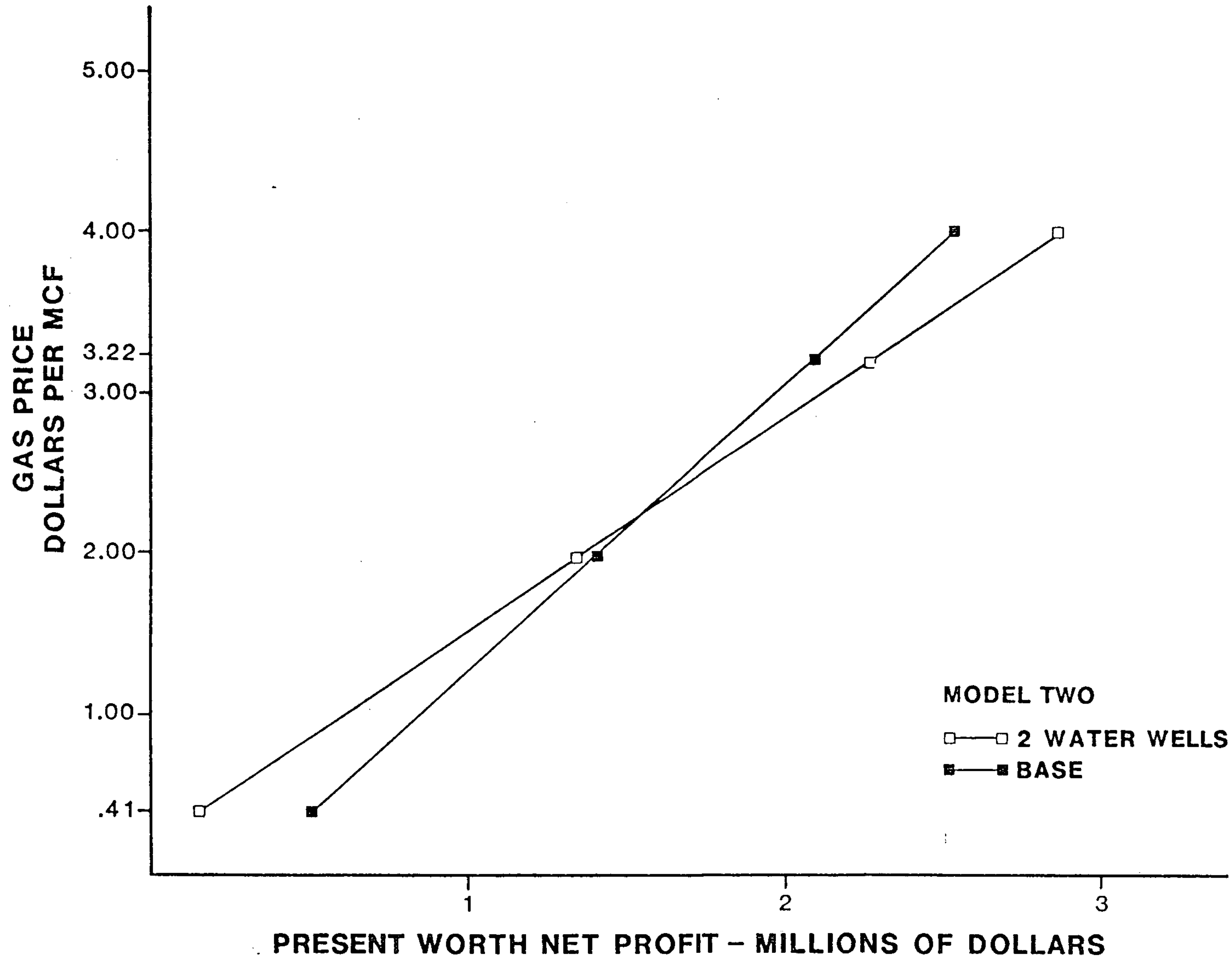


FIGURE 20A

PLAN OF IMPLEMENTATION

- Run TDT log and pressure test in gas well(s)
- Water production test in water well(s)
    - workover to place gas lift valves
    - test for maximum water production
    - run TDT log
    - pressure test
    - PVT data and water sample analysis
- Readjust evaluations if necessary
- Development of reservoir when available
    - set up monitoring equipment for engineering analysis
    - commence production and reservoir monitoring

FUTURE WORK

1. Continuation of working with Chevron towards a field test of the Eugene Island reservoir
2. Continuation of development of operator interest and participation, also, continued development of information data files
3. Continuation of selection and study of potential reservoirs, geologic studies, reservoir simulation studies, and related well logging studies
4. A detailed well testing program outline for potential field tests

Q. APPENDIX 17

N.E. HITCHCOCK SHALE STUDY

K. PETERSON - EOC

N.E. HITCHCOCK SHALE STUDY - Kim P. Peterson/Eaton

Detailed geologic study of the NE Hitchcock Field, Galveston County, Texas, by both Eaton and the BEG, along with a concurrent reservoir evaluation of the Frio 9,100' sand, set the stage for the initiation of a computer model simulation. Early work in this effort, first under IGT and later on by the University of Texas, has now been taken over by Dowdle, Fairchild and Ancell (DFA) and has been progressing quite well.

Early work by DFA, however, raised questions as to the variations in vertical as well as horizontal permeabilities throughout the reservoir. Eaton was asked to look into the possibility of shale stringers acting as perm-barriers to the upward flow of both gas and water. Although the shale study is still in progress, we have been able to identify four "major" shale and numerous minor breaks above the original gas water contact. The following discussion will impart some of the information we have learned to date.

The current version of the structure on the top of the Frio 9,100' sand is displayed in Figure 1. The map has recently been revised in the southeastern portion of the field, between wells 3, 5 and 7 to reflect data received from a recent DFA modeling run. The field is exhibited as a highly faulted, northwest plunging anticline, of moderate relief, truncated on the southeast by a low angle arcuate down-to-the-coast growth fault. Faulting throughout the field is of short displacement which allows pressure as well as fluid communication between the blocks. Wells currently active in the field are as follows:

#3	Phillips	1-Huff
#4	SGR	1-Prets
#6	SGR	1-Thompson
#8	Damson	1-Flake

Cross section H-H (Figure 2), taken through the central portion of the field, trending north-northwest/south-southeast serves a dual purpose. In addition to including the largest producers, it is drawn parallel to the axis of deposition and provides an excellent view for the description of the layering of the Frio 9,100' reservoir. There are three major depositional events which are as follows:

1. Frio B lower
2. Frio B upper
3. Frio A sand

Sand deposition in the NE Hitchcock Field area first occurred in the north-central area, found locally around well #2, leaving a 40' sand lense. This period of sand deposition, the Frio B lower sand, was followed by an area-wide draping of shale. The second event, the Frio B upper sand, was somewhat more widespread but centered generally in the northern half of the field, leaving a section of approximately 20' of sand. This period of sand deposition was followed by a longer period of quiescence in which 25' - 30' of shale accumulated field-wide. The third and last major sand depositional event, the Frio A sand, also was a widespread event leaving a thick section of sand which is the current gas producing reservoir.

A depositional facies map of the area, encompassing the NE Hitchcock Field, borrowed from Tyler-1984 (Figure 3) depicts the variation of energy levels that led to the accumulation of the sands. All sediments in the area were deposited in a distributary mouth bar and associated environments. The region displays three types of sand depositional sequences: 1) upward coarsening in the southern region, 2) upward fining in the northward areas, and 3) mixed (i.e., both upward coarsening and fining) deposits in the west.

The cross section displayed in Figure 4 highlights the four major shale lenses that have been mapped. The lenses are identified "A" through "D", respectively. It may be noted that there are additional lenses, but these are of local extent. Because of the lack of well-defined shale breaks of substantial thickness in the core recovered from the SGR 1-Delee, an arbitrary selection of 1/2 the SP (spontaneous potential) deflection was used for defining 100% shale.

The isopach of Shale Lense A (Figure 5) illustrates how widespread the shale is across the area. The lense is absent toward the southeast and contains two "permeability windows". These windows have the potential for allowing vertical migration of gas and fluids between sand lobes.

Figure 6 illustrates an isopach of Shale Lense B. The shale lense is also fairly widespread and absent along the western and southern portions of the field. The lense is thickest in the northern block and also contains a permeability window mid-field.

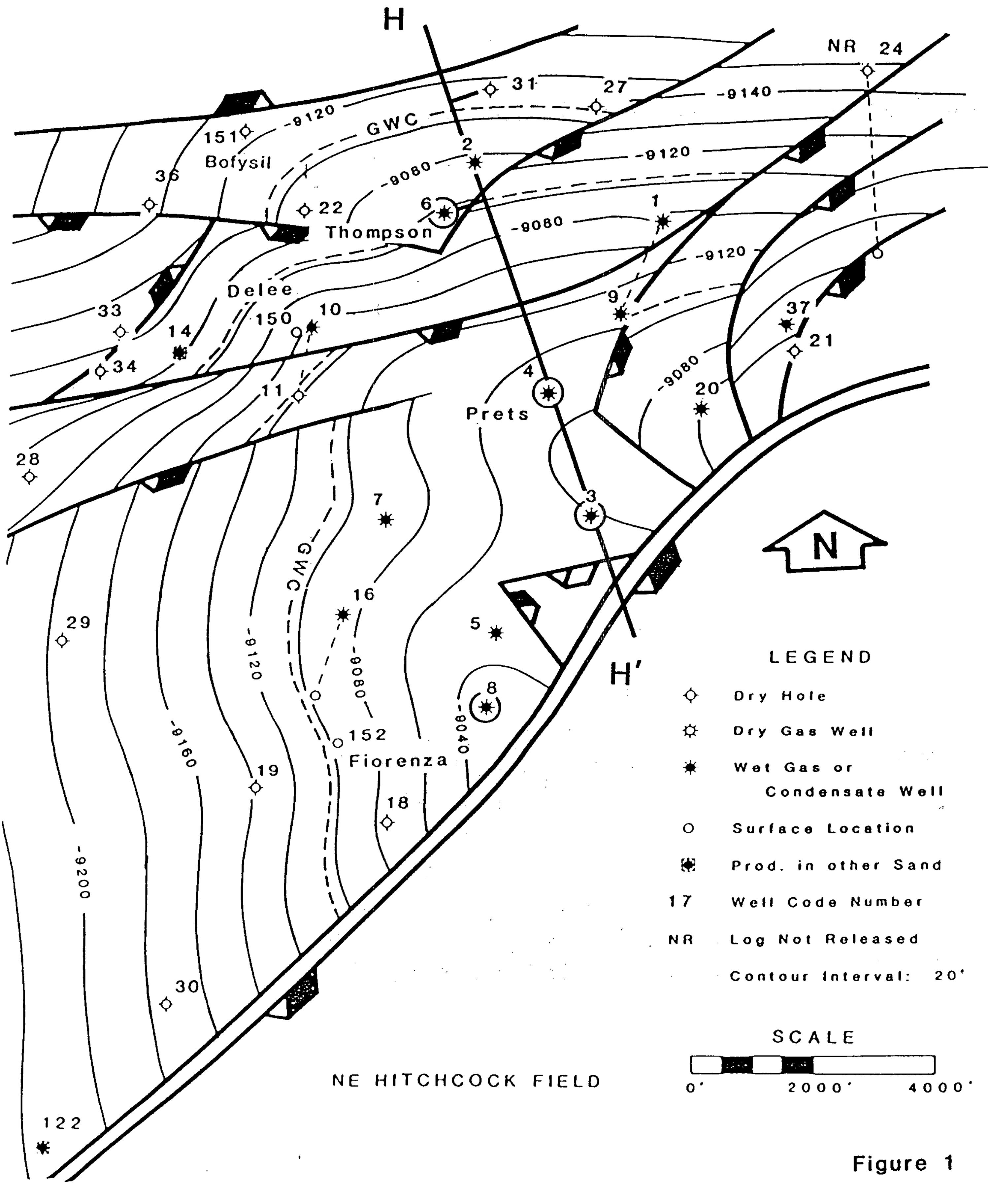
The isopach of the Shale Lense C is depicted in Figure 7. This particular lense is restricted to the central and southern portions of the field as a result of deposition of Frio A being confined to this region of the field. The lense is absent along the northeastern edge of the southern block, thickest toward the northwest area of deposition, and as in the previous lenses, contains a perm-window. This particular perm-window is adjacent to two currently active wells, #4 and #3.

The fourth isopach map of Shale Lense D is depicted in Figure 8. This lense is also restricted to the central and lower portions of the field. It is absent toward the southwest and thickest along a ridge running from well #150 toward #3.

Figure 9 illustrates an enlarged plot of the 1" electric log from the Damson 1-Flake, labeled with the major shale lense breaks. This well was drilled late in the field's history but reflects the trapping of gas below the upper shale barriers. The 16" normal is high in each instance, and the induction in the second sand lobe appears to indicate that 100% water is not reached until the middle of the second sand lobe.

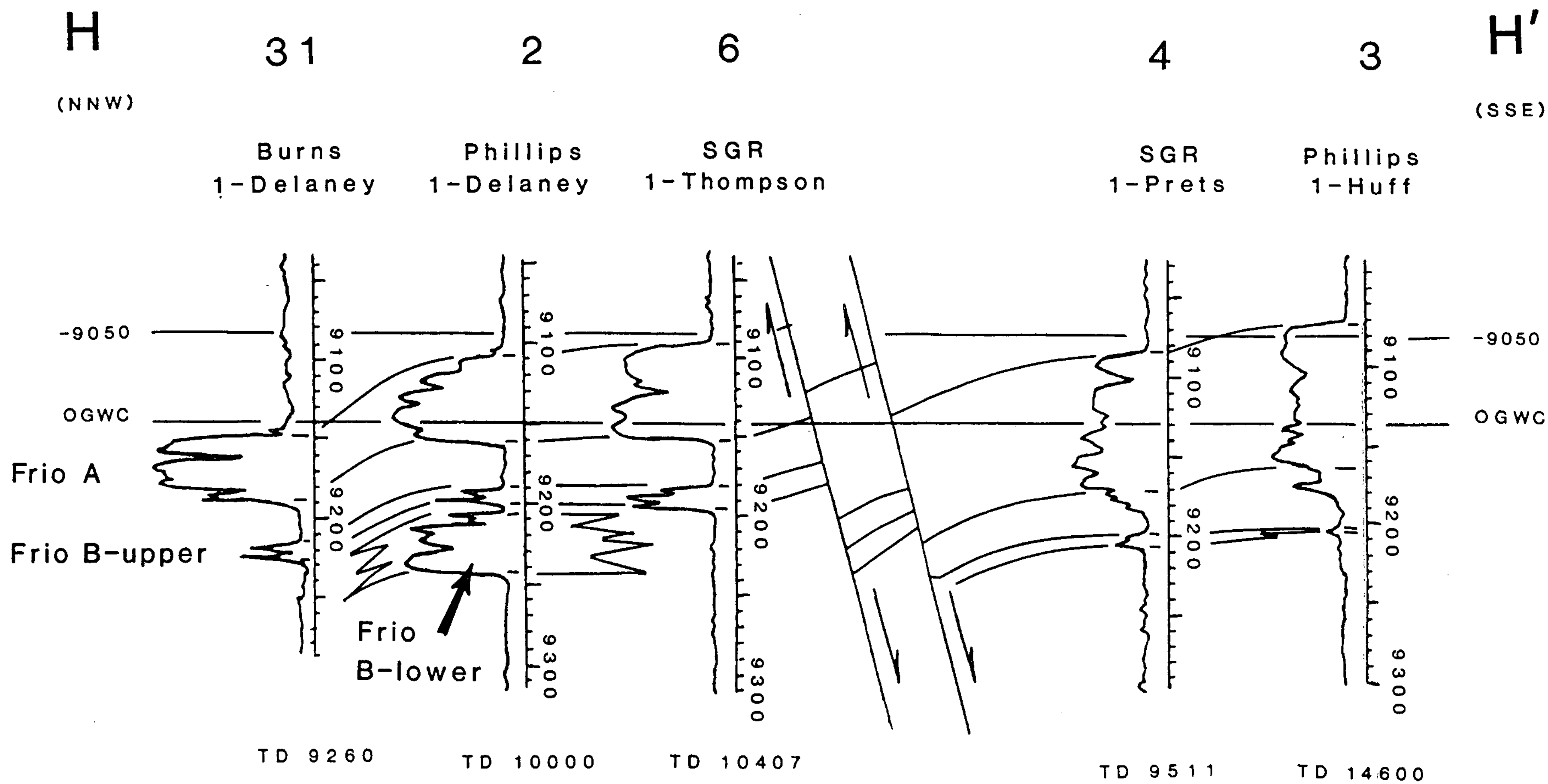
In a similar fashion, Figure 10 depicts the electric log of the SGR 1-Lemm, well #20, along the eastern portion of the field. The shale lense trapping mechanisms can also be noted in this well, specifically in the second sand lobe.

In conclusion, it is apparent that the shale lenses in the Frio 9,100' sand in the NE Hitchcock Field are acting as vertical perm-barriers. Although the reservoir as a whole is fairly homogeneous, in regarding to pressures and fluid migration, the shales have indeed created small free gas traps throughout numerous portions of the reservoir. Information of this type would be of great value to field operators on future completions, as there are additional, although small in areal extent, sources of trapped free gas.



H
H'
NR 24
31
27
-9140
-9120
GWC
151
Bofysil
2
-9120
36
-9080
22
6
Thompson
1
-9080
-9120
Delee
33
10
150
9
37
21
14
34
4
-9080
11
Prets
20
28
7
3
N
GWC
16
29
5
-9120
-9080
8
-9160
152
Fiorenza
-9040
19
18
-9200
30
122
LEGEND
Dry Hole
Dry Gas Well
Wet Gas or Condensate Well
Surface Location
Prod. in other Sand
17 Well Code Number
NR Log Not Released
Contour Interval: 20'
SCALE
0'
2000'
4000'
NE HITCHCOCK FIELD

Figure 1



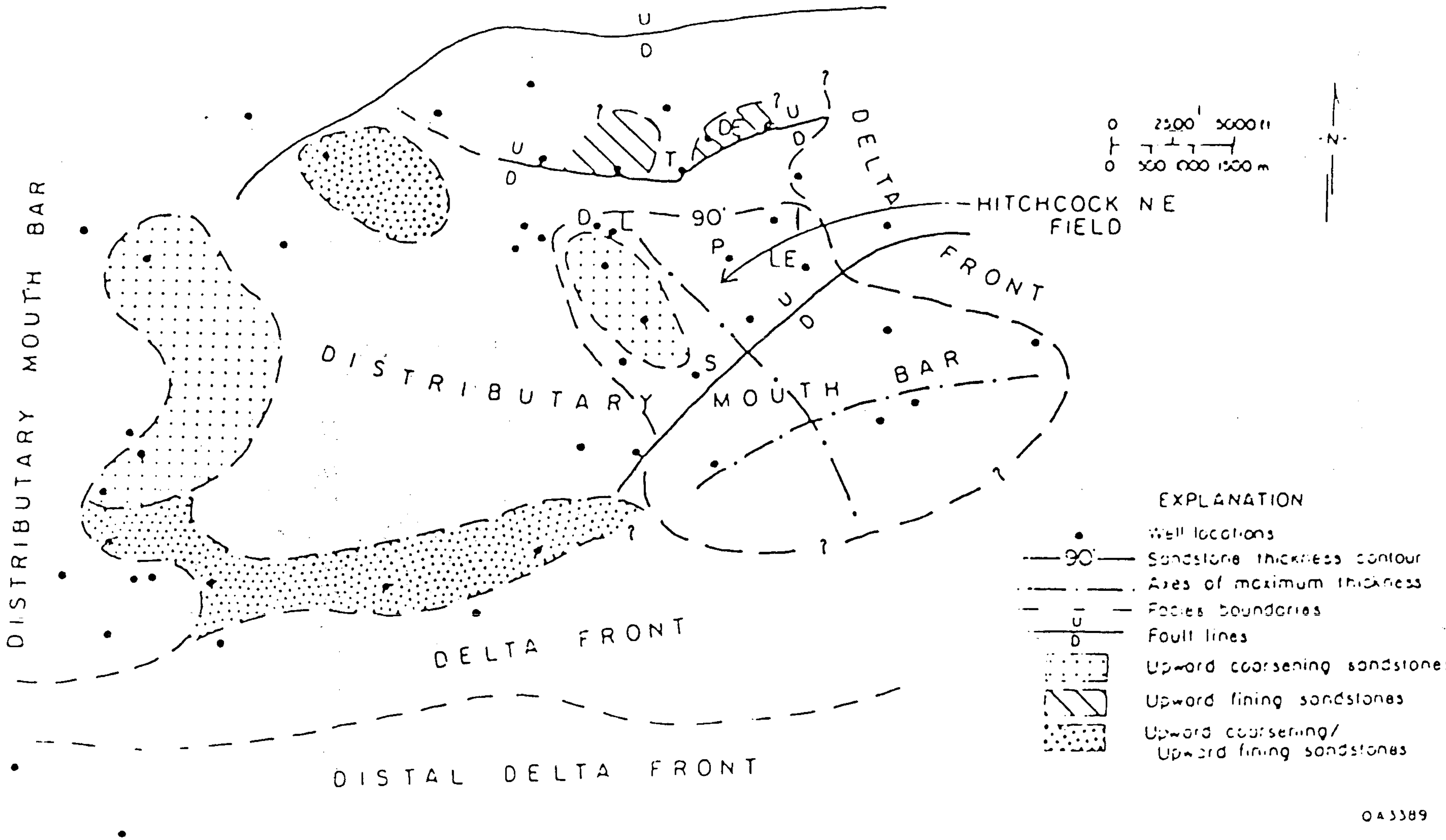
Scale:

Vertical: 1'': 100'

Horizontal: Non-scalar

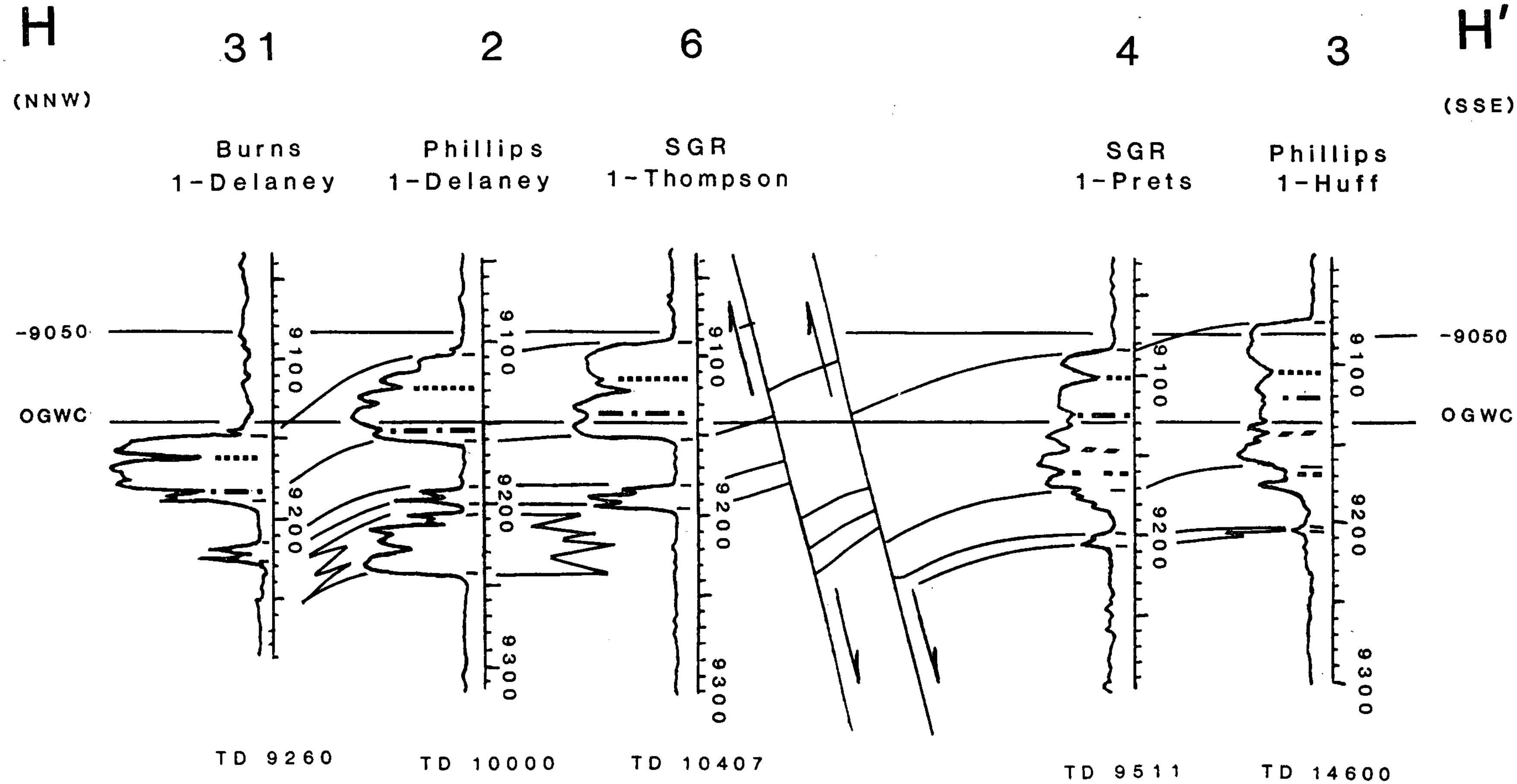
EATON OPERATING COMPANY, INC.		
Cross Section H-H' NE Hitchcock Field Galveston Co. Texas		
	K Peterson	3/5/86

Figure 2



Log facies map of the Hitchcock N.E. field (modified from Tyler, 1984).

Figure 3



Scale:

Vertical: 1'': 100'

Horizontal: Non-scalar

Shale Lense A

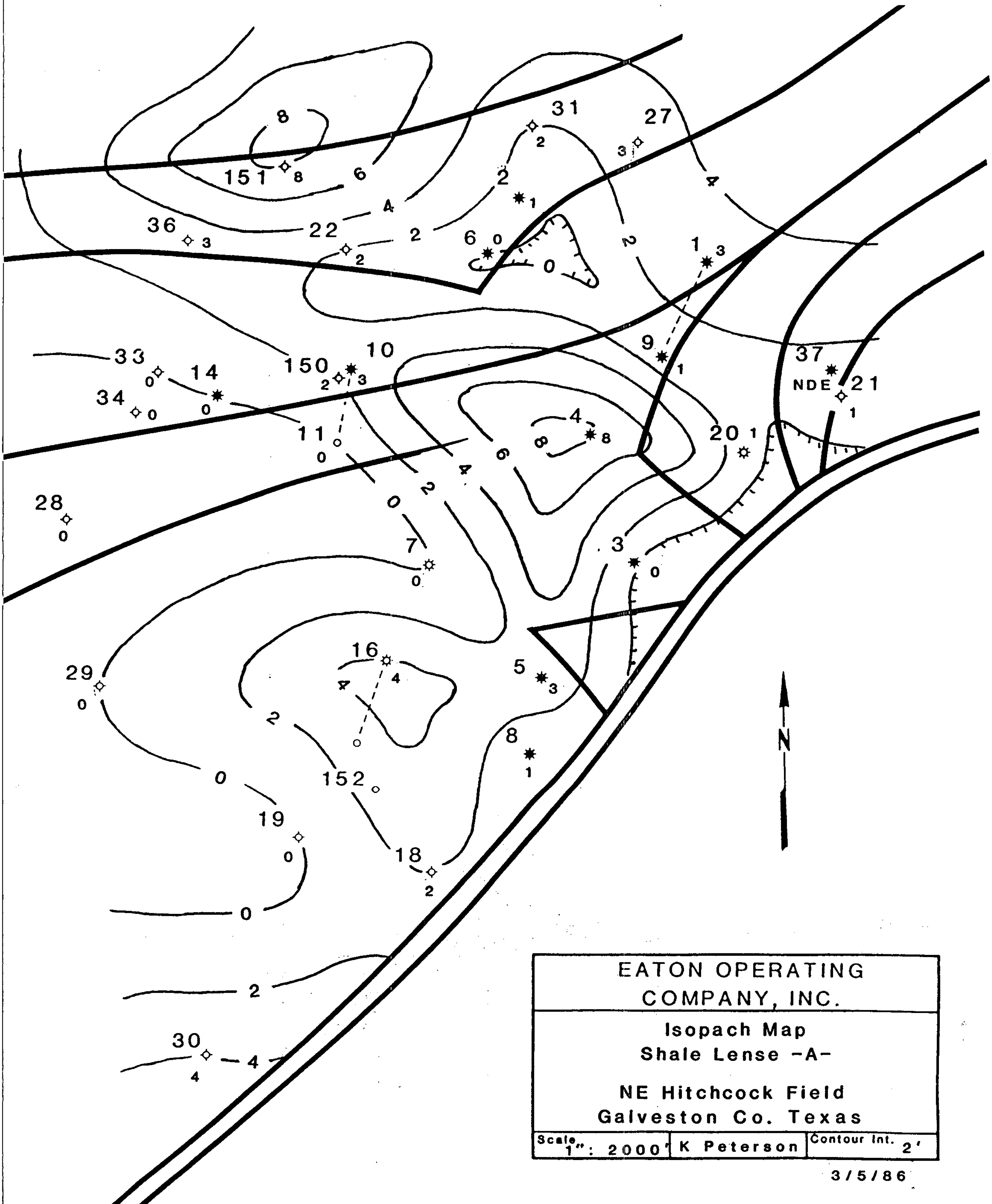
" " B

" " C

" " D

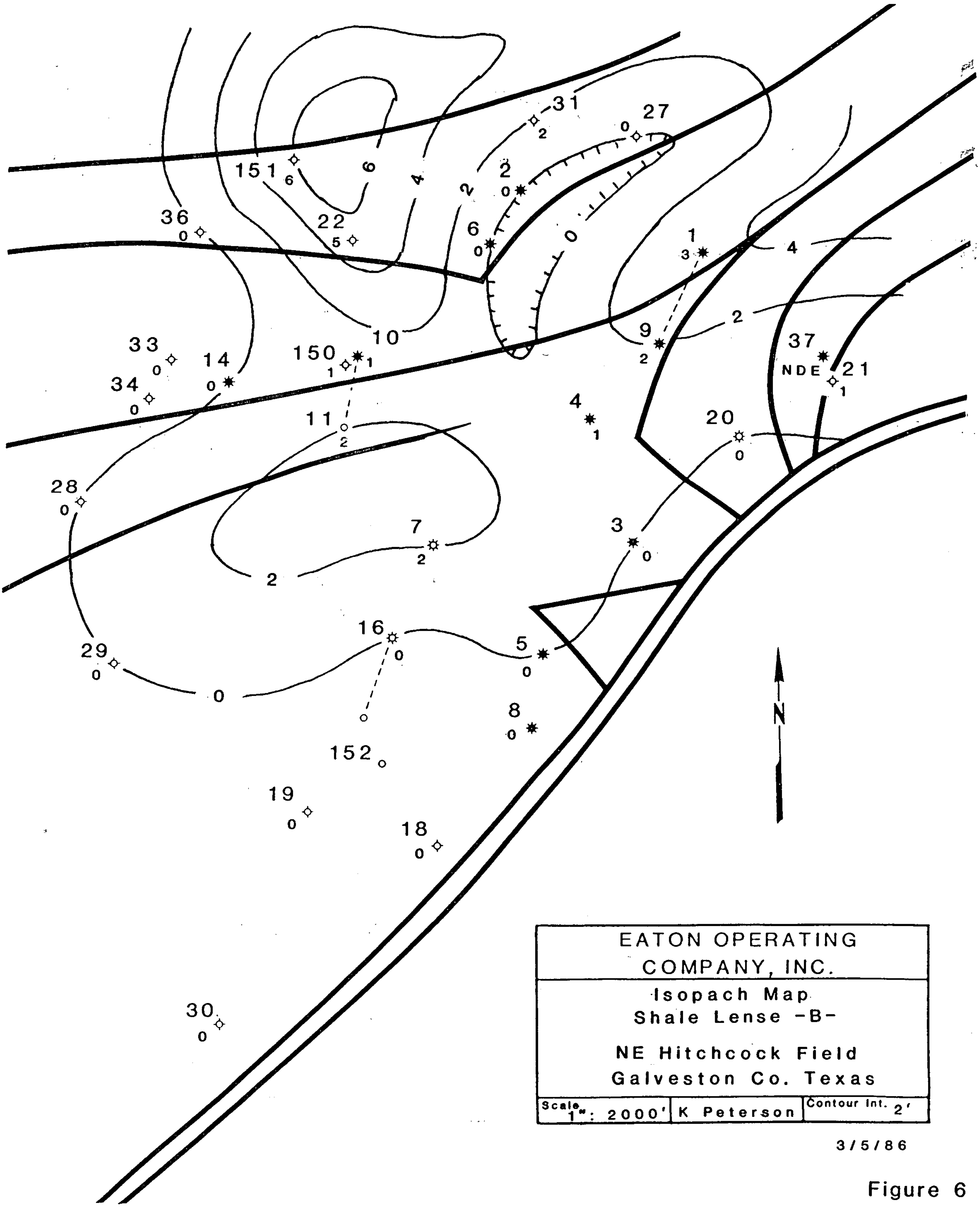
EATON OPERATING COMPANY, INC.		
Cross Section H-H'		
NE Hitchcock Field		
Galveston Co. Texas		
	K Peterson	3/5/86

Figure 4



EATON OPERATING
COMPANY, INC.
Isopach Map
Shale Lense -A-
NE Hitchcock Field
Galveston Co. Texas
Scale 1": 2000'
K Peterson
Contour Int. 2'
3/5/86
N
NDE

Figure 5



EATON OPERATING COMPANY, INC.

Isopach Map
Shale Lense -B-

NE Hitchcock Field
Galveston Co. Texas

Scale 1": 2000'	K Peterson	Contour Int. 2'

3/5/86

Figure 6

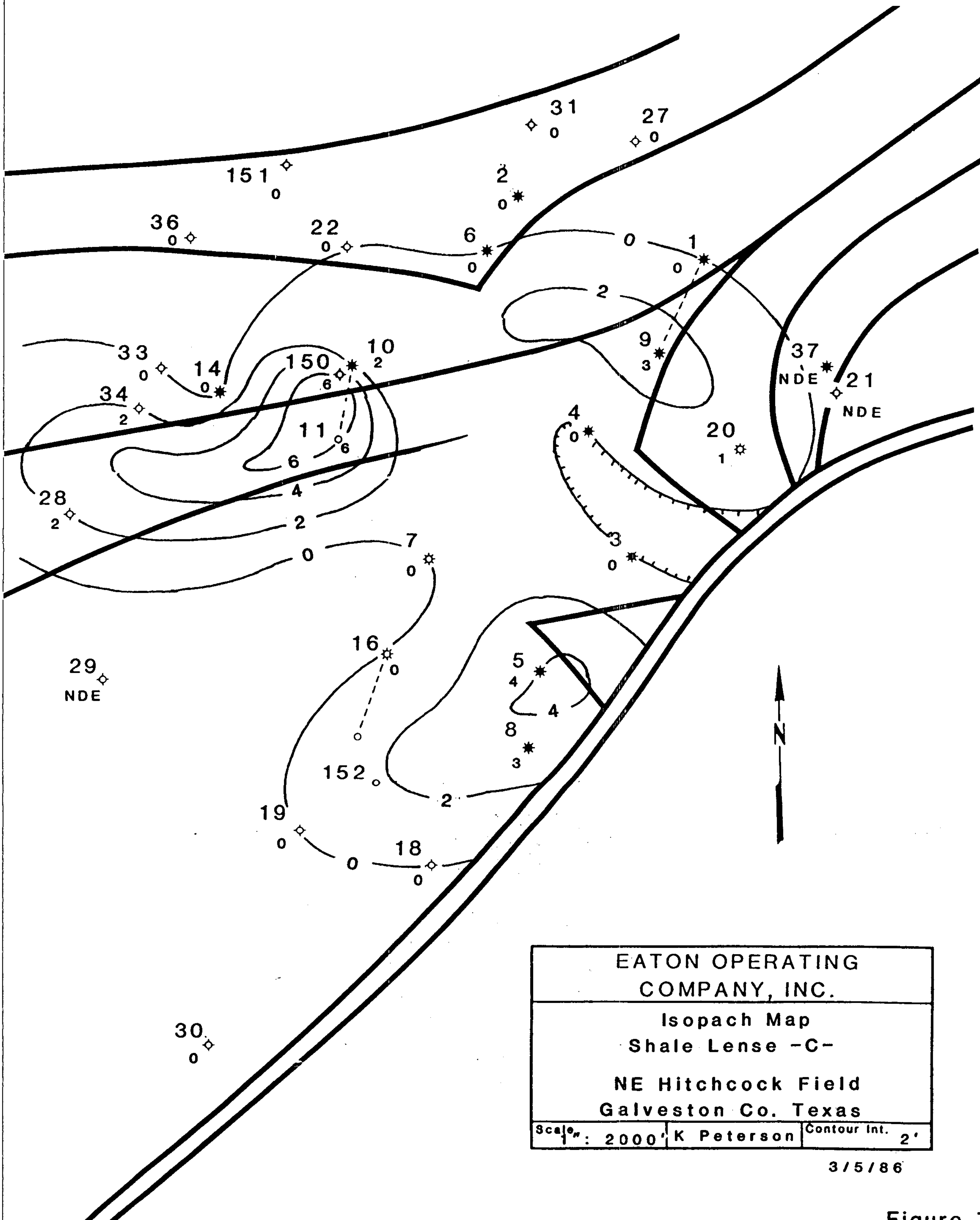

EATON OPERATING COMPANY, INC.
Isopach Map
Shale Lense -C-
NE Hitchcock Field
Galveston Co. Texas
Scale 1": 2000'
K Peterson
Contour Int. 2'
3/5/86
N
151
31
27
2
36
22
6
1
33
14
10
150
9
37
21
34
11
4
20
28
7
3
29
16
5
8
152
19
18
30
NDE

Figure 7

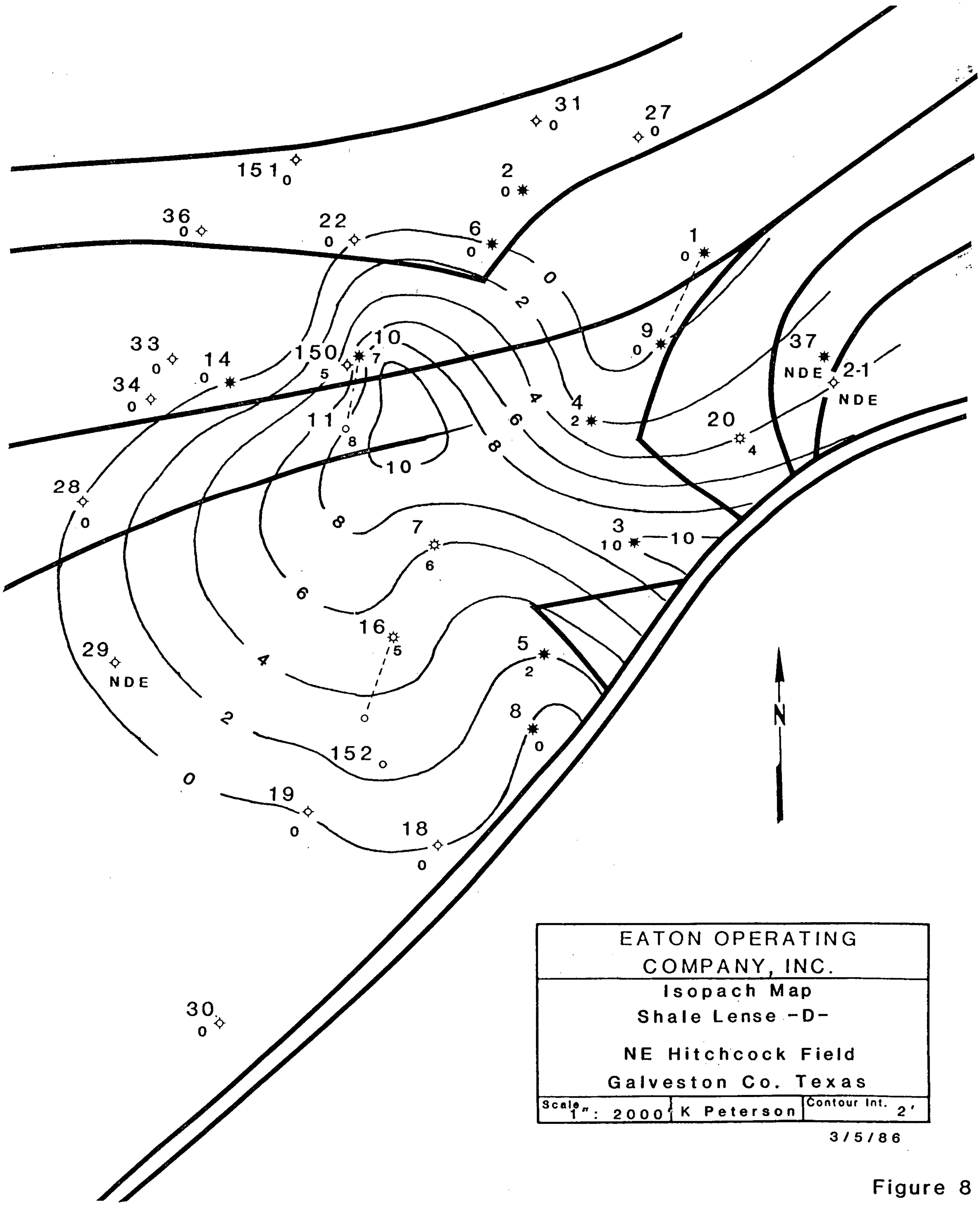

N
EATON OPERATING COMPANY, INC.
Isopach Map
Shale Lense -D-
NE Hitchcock Field
Galveston Co. Texas
Scale 1": 2000'
K Peterson
Contour Int. 2'
3/5/86

Figure 8

Damson 1 - Flake

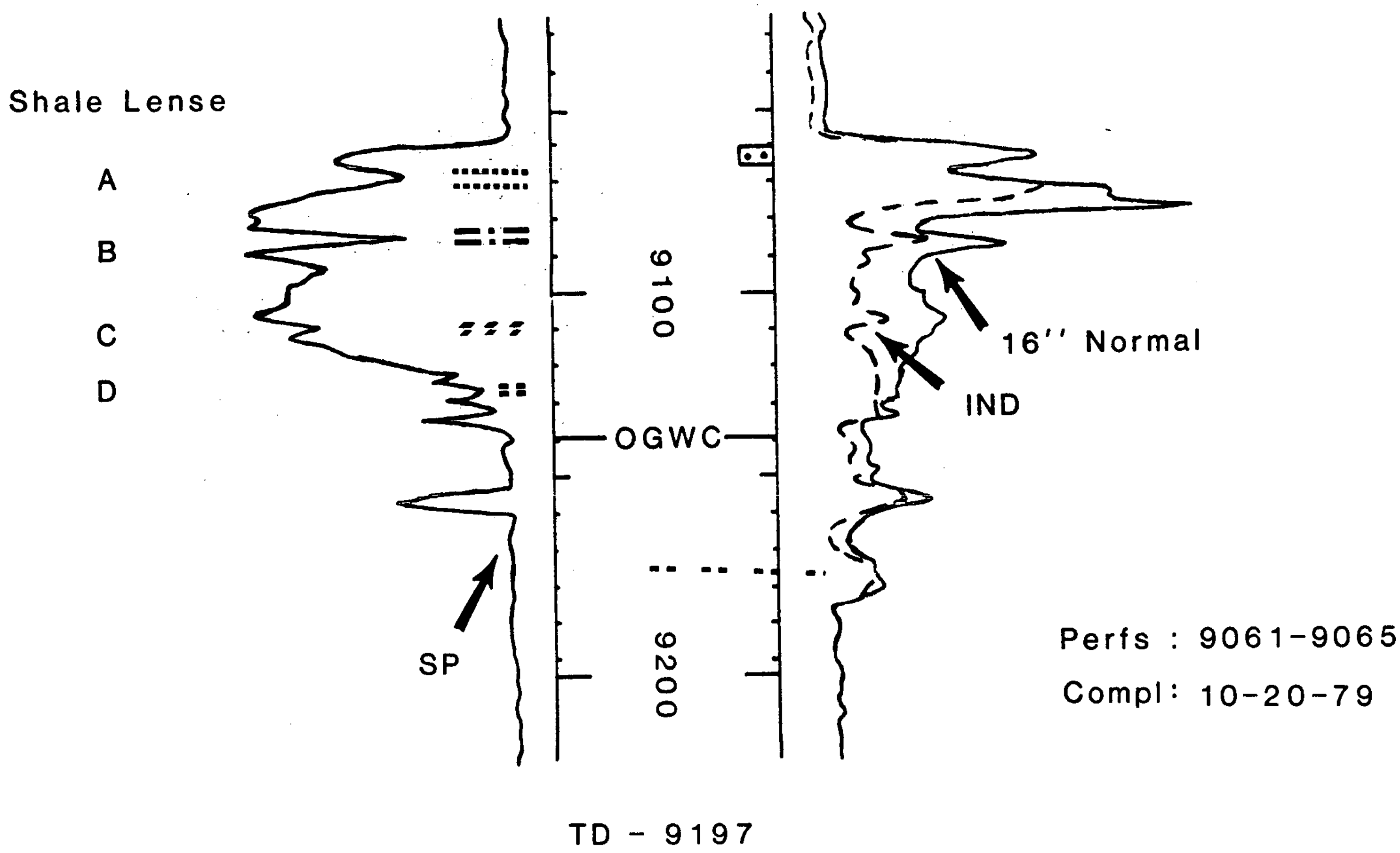


Figure 9

SGR 1 - Lemm

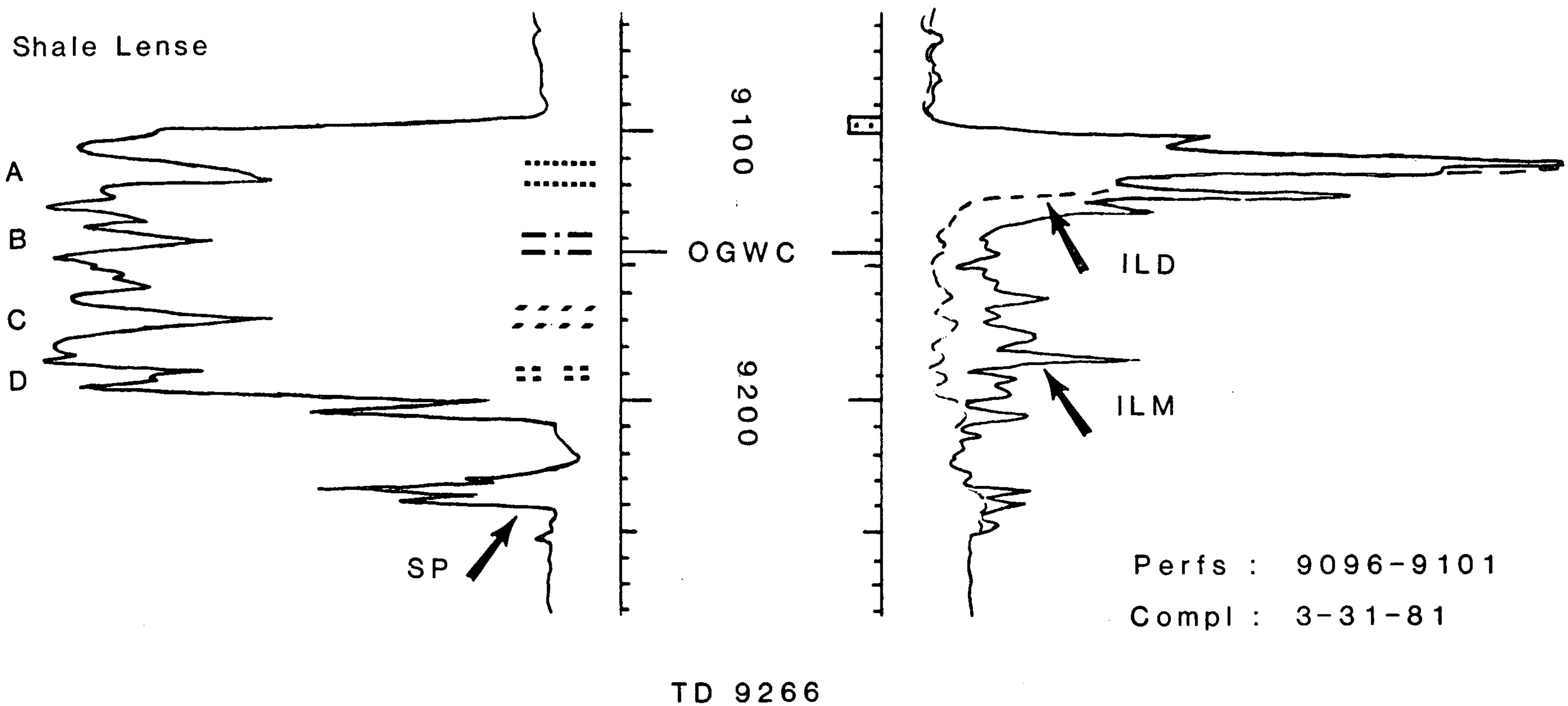


Figure 10

R. APPENDIX 18

FIELD TEST RESULTS FROM N.E. HITCHCOCK WELLS

P. RANDOLPH - IGT

N.E. HITCHCOCK WELLS

P.L. Randolph

Institute of Gas Technology

This presentation summarizes co-production results from two wells in the N.E. Hitchcock field since the onset of co-production operations at the end of February, 1983.

More than 80 BCF were conventionally produced from the 9100 foot deep Frio "A" sand in this field from a total of 12 wells between 1958 and 1982. Wells were plugged and abandoned as operating economics became unfavorable under low regulated gas prices. Gas phase reservoir pressure was a minimum of about 3850 psi in the early 1970's and had increased to more than 4050 psi before the Prets Unit No. 1 well (#4 in Figure 1), was re-entered and completed for high volume brine production in February 1982.

Figure 2 shows the current surface hardware configuration for the Prets well. Use of multiple dump valves on the separator has made possible production of 4000+ BWPD with a flowing wellhead pressure of only about 100 psi. About 2/3 of the 50 BOPD are recovered from the three phase separator and gunbarrel separator. The remainder condenses from the 1 MMCF/D of produced gas after the gas leaves the 195 Deg F separator.

The plot of histories of brine rate, gas rate, and wellhead pressure show the result of a learning process characterized by pursuit of means to increase brine rate and decrease flowing wellhead pressure. The increase in gas rate is a result of these actions.

Scaling of tubulars was recognized as a problem when the master valves were very hard to close in preparation for Hurricane Alecia in the 3rd quarter of 1983. The jumps in brine and gas rates in the 4th quarter of 1983 were the result of acid treatment to remove scale from the 2-7/8 inch tubing. Scale was then controlled with inhibitor squeezes until the 3rd quarter of 1985. Since then, periodic acid cleanouts have been used as will be discussed later.

Gas production through 1984 is beleived to be primarily from attic gas previously abandoned in place (solution gas provides less than 10% of production). But, early in 1985, flowing pressure in the vicinity of the Prets well was reduced to below the trapping pressue of 3850 psi. Since then, liberation of gas, trapped in 30% of pore volume by invading brine, has supplemented the attic gas to reverse the decline in production rate.

Re-entry of the Thompson Unit No. 1 well (#6 in Figure 1) in April 1984 revealed a quite different response. For several months attic gas provided a flowing tubing pressure high enough for direct sale to the pipeline. During the 3rd quarter of 1984, compression was added to permit lower wellhead pressure. Brine rate increase and gas production more than doubled. But, attic gas production then again took a nosedive. Brine rate was further increased in the 4th quarter by converting from tubing to annulus flow. However, the upturn in gas production due to liberation of gas trapped during brine imbibition has yet to materialize.

The produced gas/brine ratios for the two wells are both shown in another figure.

A final figure shows a natural cycle in Prets well gas production rate that must be recognized in field evaluation of changes in hardware or operating proceedures. The reason has not been identified but it is speculated that earth tides may cause enough strain to change the very steep relative permeability to gas. The sawtooth superposed on the cycles starting in October 1985 are the result of periodic acid treatments to remove scale from the production tubing. Details and timing of the treatments have changed as understanding is gained. The reason for acid treatments, rather than inhibitor squeezes, is cost. Swabbing and days of lost production are a real part of inhibitor squeeezes with sub-hydrostatic reservoir pressure. But, scale forms only in the shallowest 1000 feet of the tubing and can be removed with acid in a time less than the bubble rise time in the well and without killing the well.

The major question in ultimate recovery from co-production is the minimum reservoir pressure that it will be practicable to achieve. Preliminary studies by this author, presented in the Sixth Goepressured, Geothermal Symposium, suggested that 3000 psi may well be a minimum for natural gas lift in this reservoir. But, it is conceivable that inguenuity will produce still lower minimum pressure with continuing favorable economics.

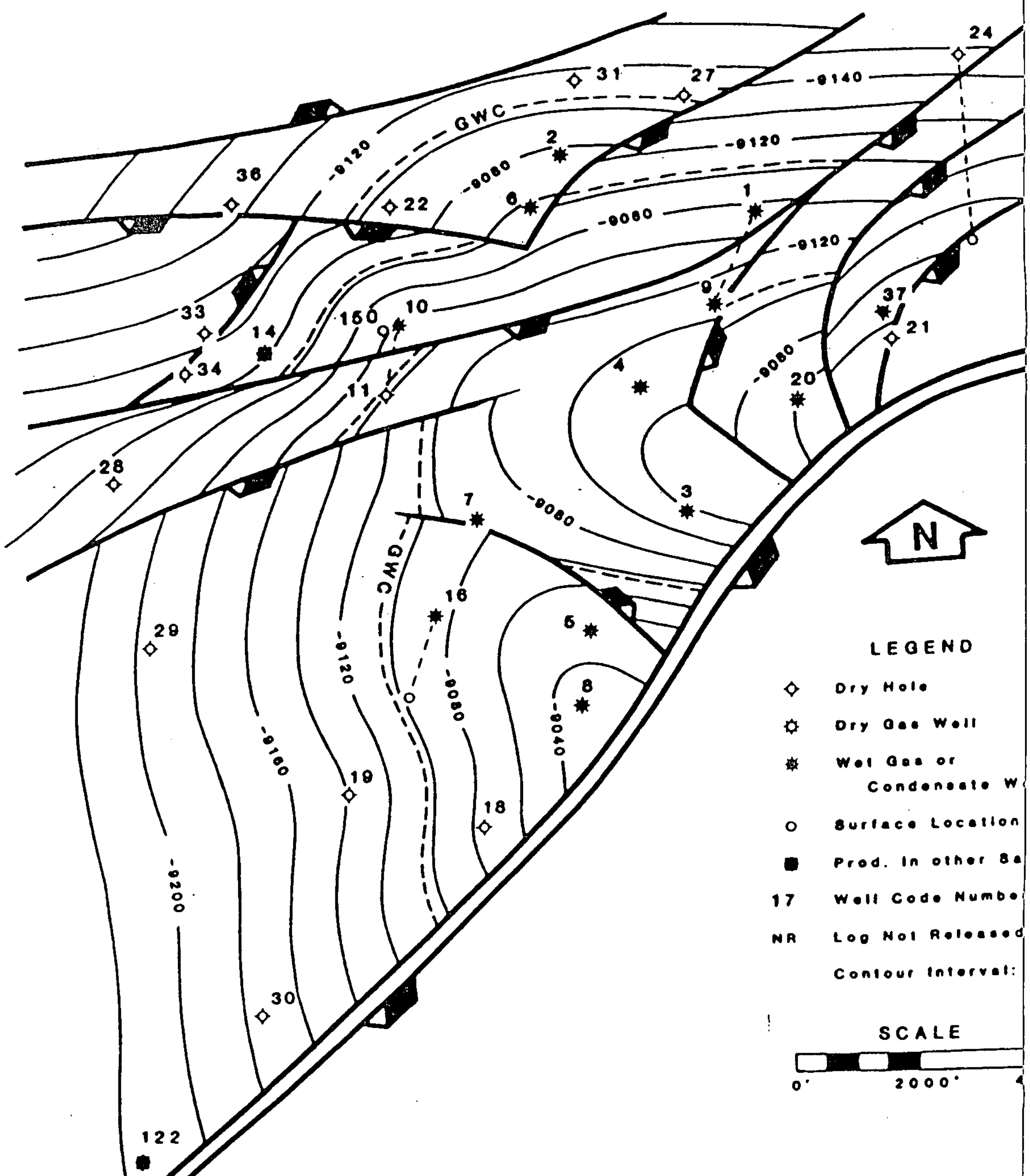


Fig. 1. Structure map on top of Frio pay zone

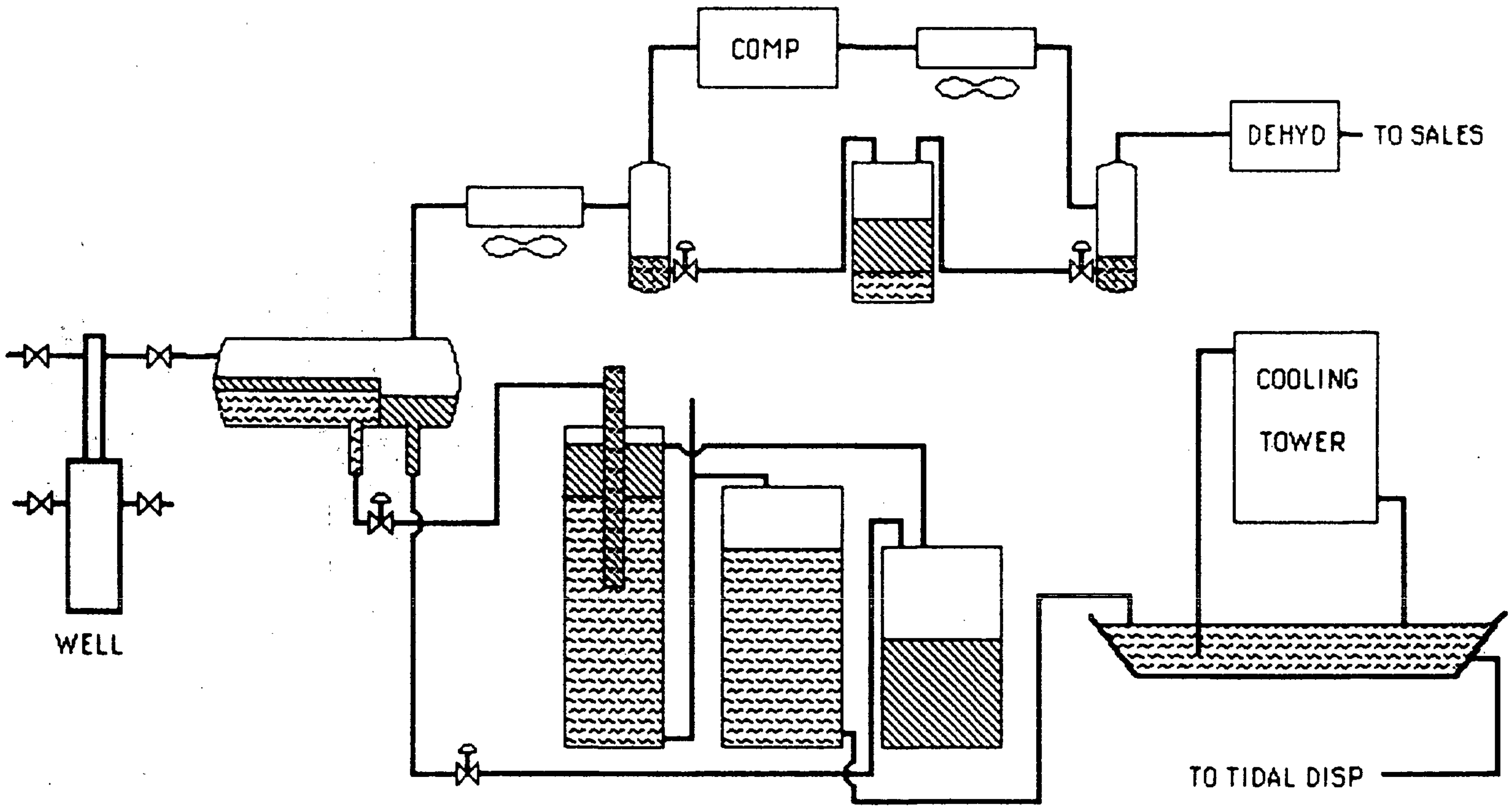
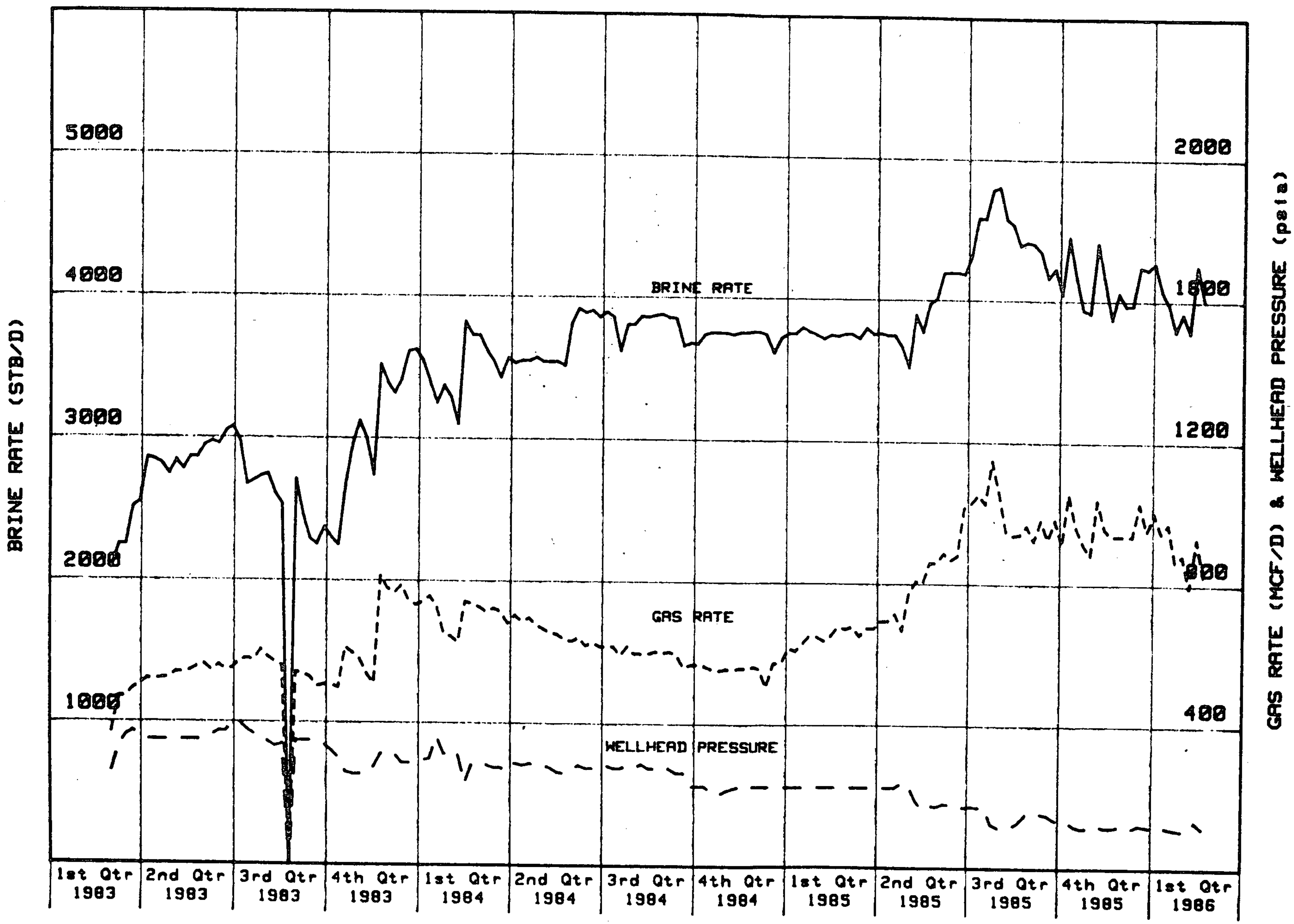
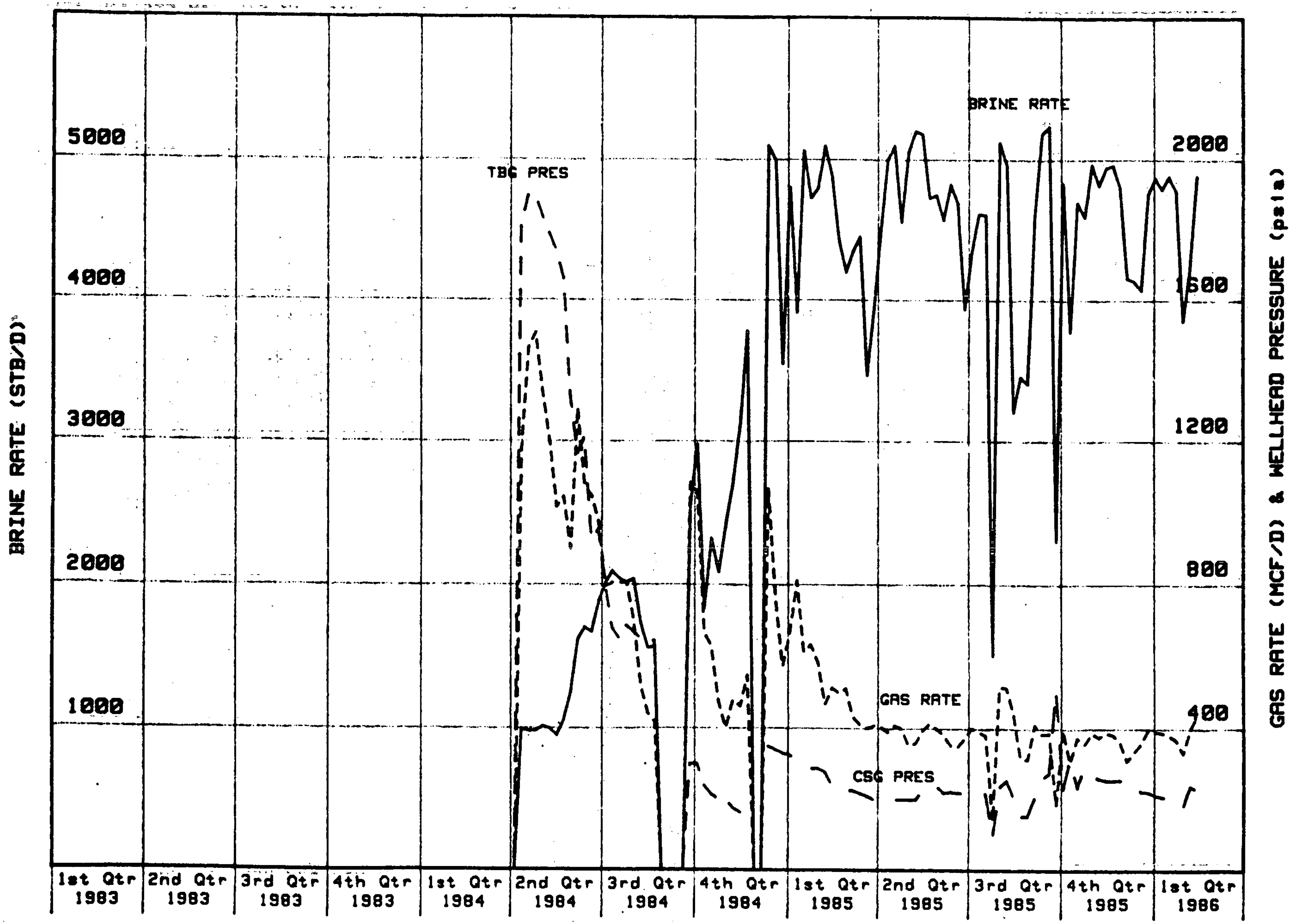


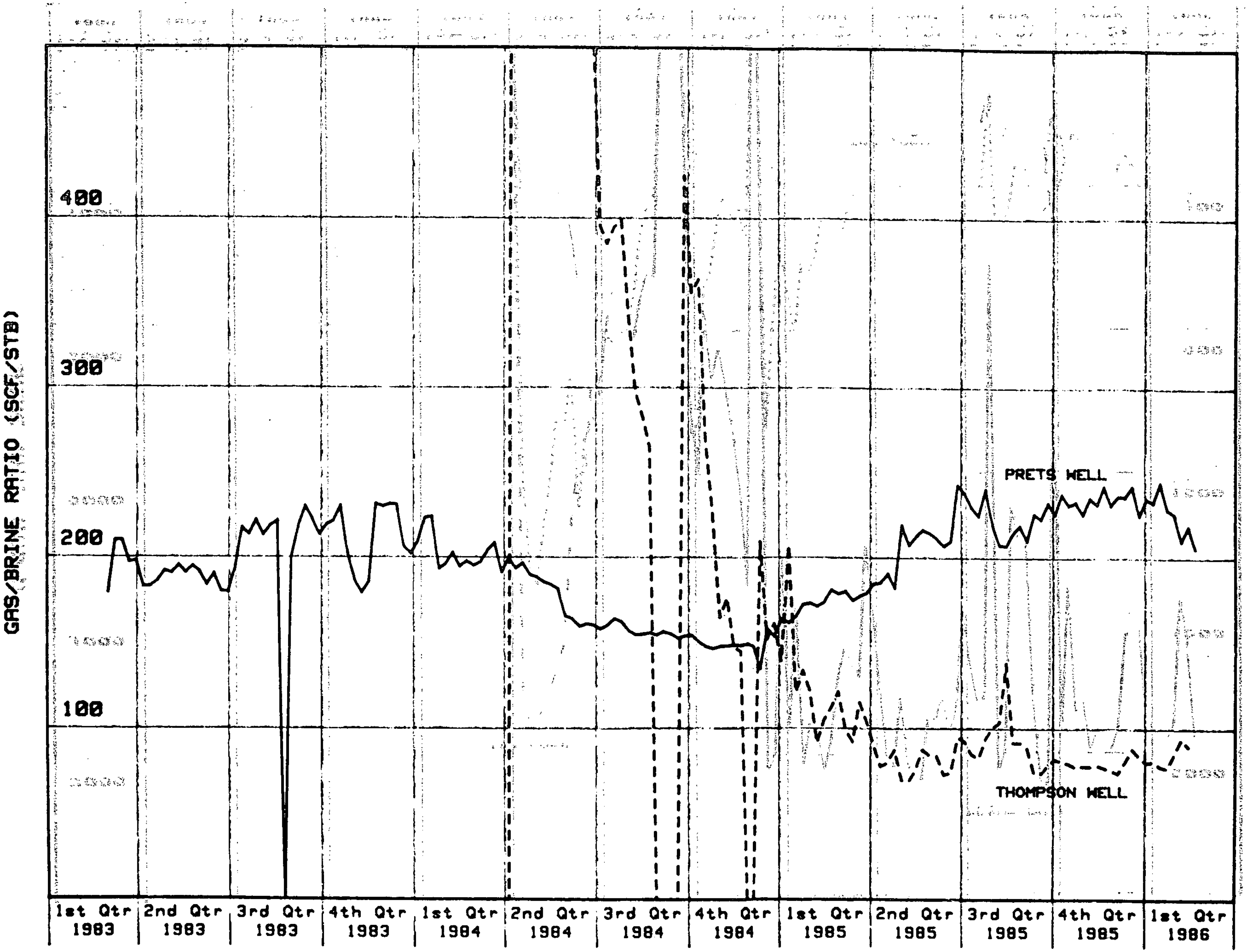
Figure 2: Prets Well Surface Facilities



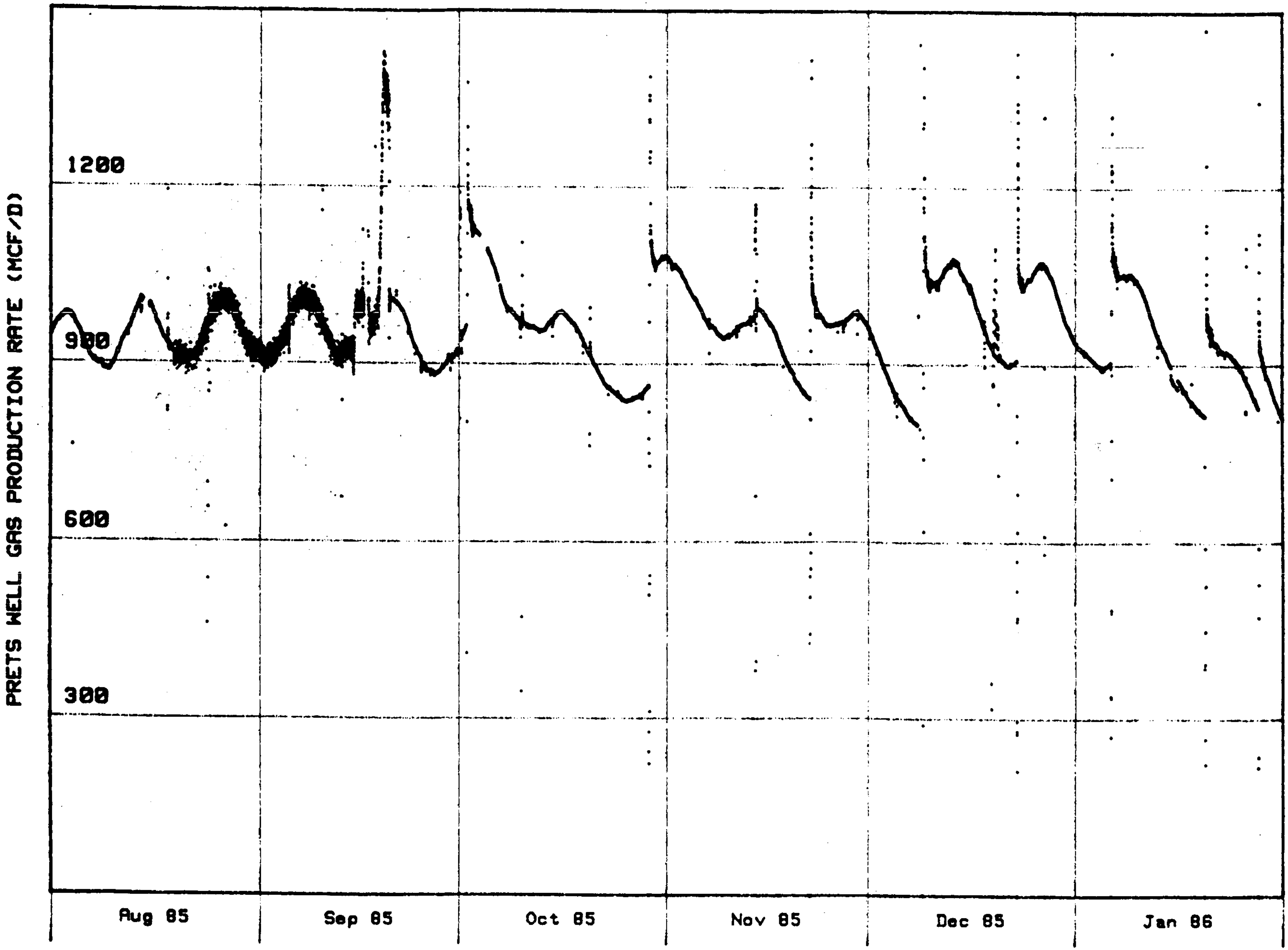
BRINE RATE (STB/D)
GAS RATE (MCF/D) & WELLHEAD PRESSURE (psia)
5000
4000
3000
2000
1000
2000
1600
1200
800
400
BRINE RATE
GAS RATE
WELLHEAD PRESSURE
1st Qtr 1983
2nd Qtr 1983
3rd Qtr 1983
4th Qtr 1983
1st Qtr 1984
2nd Qtr 1984
3rd Qtr 1984
4th Qtr 1984
1st Qtr 1985
2nd Qtr 1985
3rd Qtr 1985
4th Qtr 1985
1st Qtr 1986



BRINE RATE
TBG PRES
GAS RATE
CSG PRES
BRINE RATE (STB/D)
GAS RATE (MCF/D) & WELLHEAD PRESSURE (psia)
5000
4000
3000
2000
1000
2000
1600
1200
800
400
1st Qtr 1983
2nd Qtr 1983
3rd Qtr 1983
4th Qtr 1983
1st Qtr 1984
2nd Qtr 1984
3rd Qtr 1984
4th Qtr 1984
1st Qtr 1985
2nd Qtr 1985
3rd Qtr 1985
4th Qtr 1985
1st Qtr 1986



GAS/BRINE RATIO (SCF/STB)
400
300
200
100
PRETS WELL
THOMPSON WELL
1st Qtr 1983
2nd Qtr 1983
3rd Qtr 1983
4th Qtr 1983
1st Qtr 1984
2nd Qtr 1984
3rd Qtr 1984
4th Qtr 1984
1st Qtr 1985
2nd Qtr 1985
3rd Qtr 1985
4th Qtr 1985
1st Qtr 1986



PRETS WELL GAS PRODUCTION RATE (MCF/D)
1200
900
600
300
Aug 85
Sep 85
Oct 85
Nov 85
Dec 85
Jan 86

HITCHCOCK HYDROCARBONS

* According to IGT measurements, between 50 and 150 MCF hot vapor per day were being lost through the 2 in. pipe vent on the Prets brine tank.

* Additional vapors were being lost through bad hatch seals on the brine tank and gun barrel.

* The vapor was passed through a coil at ice temperature.

* The resulting gas and liquids were analyzed.

* Water vapor was found to be a major component of the hot vapor.

* A non-condensable gas (50% C1, 10% C2, 10% C3) was also a major part of the hot vapors.

* The condensable hydrocarbon part accounted for several % of the hot vapor.

* The condensable hydrocarbons contained Cr through C15, but C7 and C8 accounted for 50 wt % of this sample.

* Analyses of the Prets separator gas and sales gas showed that approximately 12 bbls per day of light hydrocarbon liquids are being lost between the separator and sales line.

HITCHCOCK HYDROCARBONS (CONT.)

* THESE LIQUIDS ARE COMING OUT AT THE COMPRESSOR, DEHYDRATION UNIT, AND COOLER. ALL THESE LIQUIDS WERE BEING PLACED INTO THE HOT GUN BARREL/BRINE TANK AND BOILING AWAY.

* IGT SUGGESTED THAT THESE LIQUIDS BE COLLECTED IN A SEPARATE TANK RATHER THAN THE HOT GUN BARREL.

* THE PLACEMENT OF THE LIQUIDS FROM JUST THE COMPRESSOR AND DEHYDRATION UNIT INTO A SEPARATE TANK HAS RESULTED IN THE COLLECTION OF AN ADDITIONAL 6 BBLS LIQUID HYDROCARBONS PER DAY.

HITCHCOCK PVT

* A PVT study on the Thompson Well in 1959 shows that there was no mobile liquid hydrocarbon phase being produced at that time.

* That study also showed that the reservoir would go into retrograde condensation with production.

* Retrograde condensation would produce enough liquid hydrocarbons to fill 9.7 to 11% of pore volume by the time of the PVT studies IGT had done. (Assuming a constant volume reservoir and no production of reservoir liquid hydrocarbons.)

* The Thompson PVT study which IGT had done 8/1/84 showed that 2.56% of the reservoir volume of produced hydrocarbons was in the liquid phase in the reservoir.

* The Prets PVT study which IGT had done 8/1/84 showed that 12.2% of the reservoir volume of produced hydrocarbons was in the liquid phase in the reservoir.

HITCHCOCK SOLIDS

* IGT filtered disposal brine and found about 17 lbs. of solids per 1000 bbls.

* Most of these solids were found to be iron oxides/hydroxides formed when the brine is exposed to oxygen in the air.

* IGT measured the amount of air introduced into the Thompson brine tank as the brine level fell when the brine disposal pump was on.

* IGT concluded that the oxygen in this air was responsible for the formation of the iron oxides/hydroxides.

* IGT informed the operator of the above and helped him design a system which puts produced gas instead of air into the brine tank.

* This system proved to very greatly reduce the amount of iron oxides/hydroxides in the disposal brine.

HITCHCOCK MODELING

- IGT has obtained a very satisfactory history match to the most extended period (20.9 days) of production data from the DeLee Unit Well No. 1, using a two-phase reservoir simulator.

- A 5000 ft. radius right circular cylinder reservoir was used to model near wellbore effects.

- Water-drive was supplied by an aquifer surrounding the reservoir with the same upper and lower boundaries.

- Appropriate assignment of gas and water relative permeabilities was the most crucial factor in modeling flowing well behavior.

- The best history match was made using:

$$krg = \left(1 - \frac{Sw - .225}{.476}\right)^{1.3357}$$

$$krw = \left(\frac{Sw - .225}{.775}\right)^{2}$$

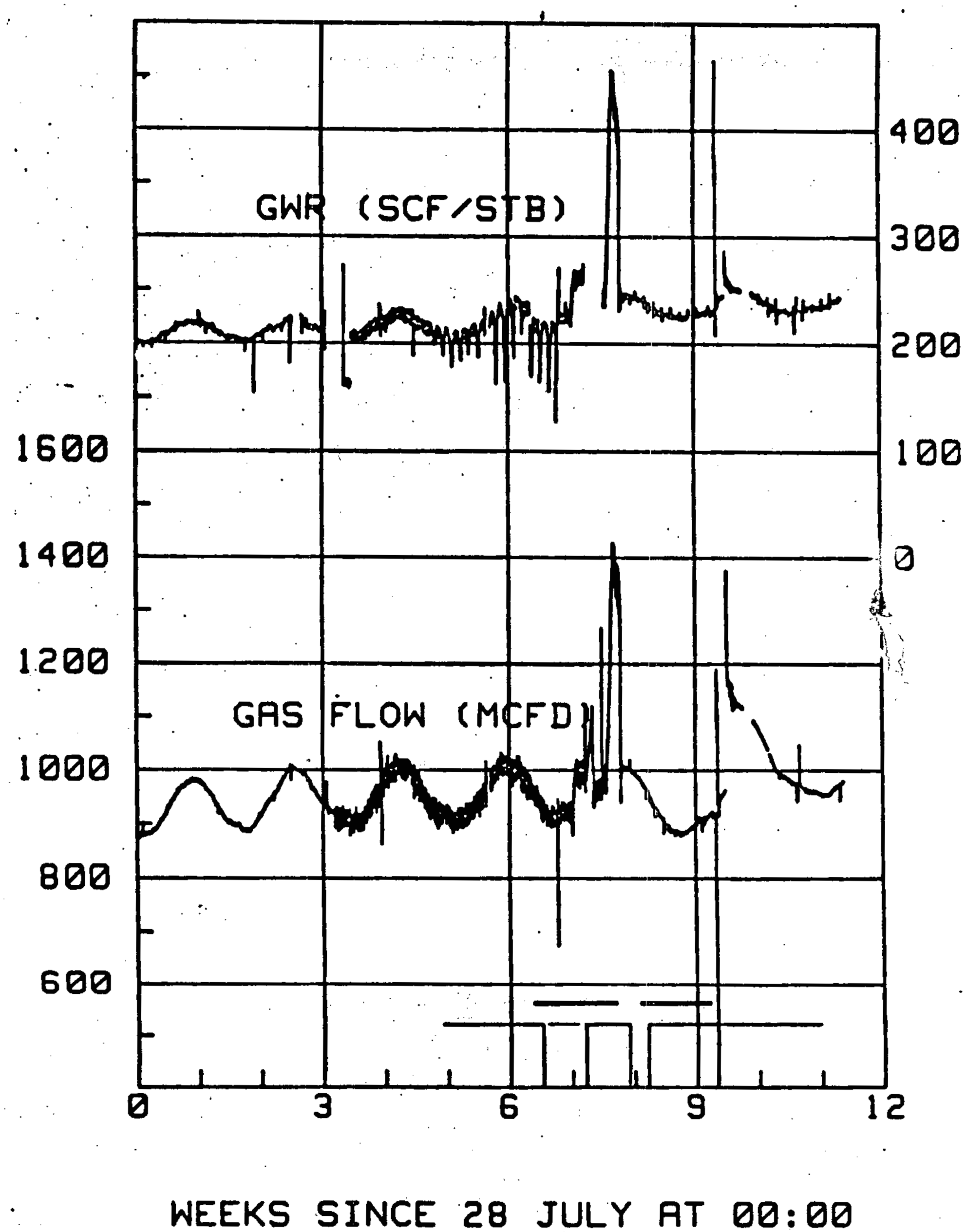


Figure 1. Cyclic Variation in Prets Gas Rate

Studying this is neither within our scope of work nor is money available. This may be the effect of drive provided by tides. Understanding of this data might provide another way to determine reservoir properties.

FIELD AND LABORATORY SUPPORT FOR THE CO-PRODUCTION OF GAS AND WATER PROGRAM

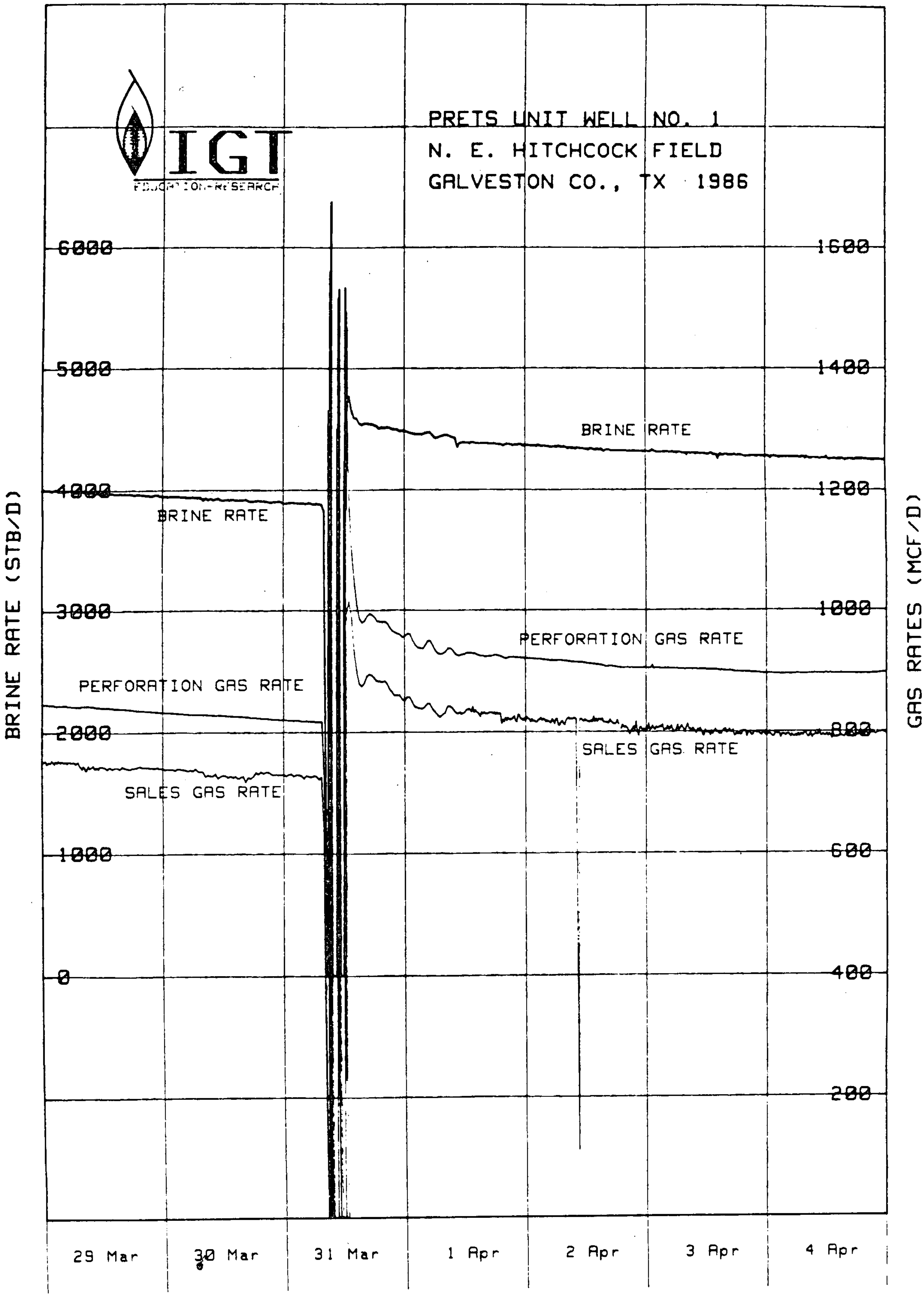
Institute of Gas Technology

<u>Specific Objectives:</u>

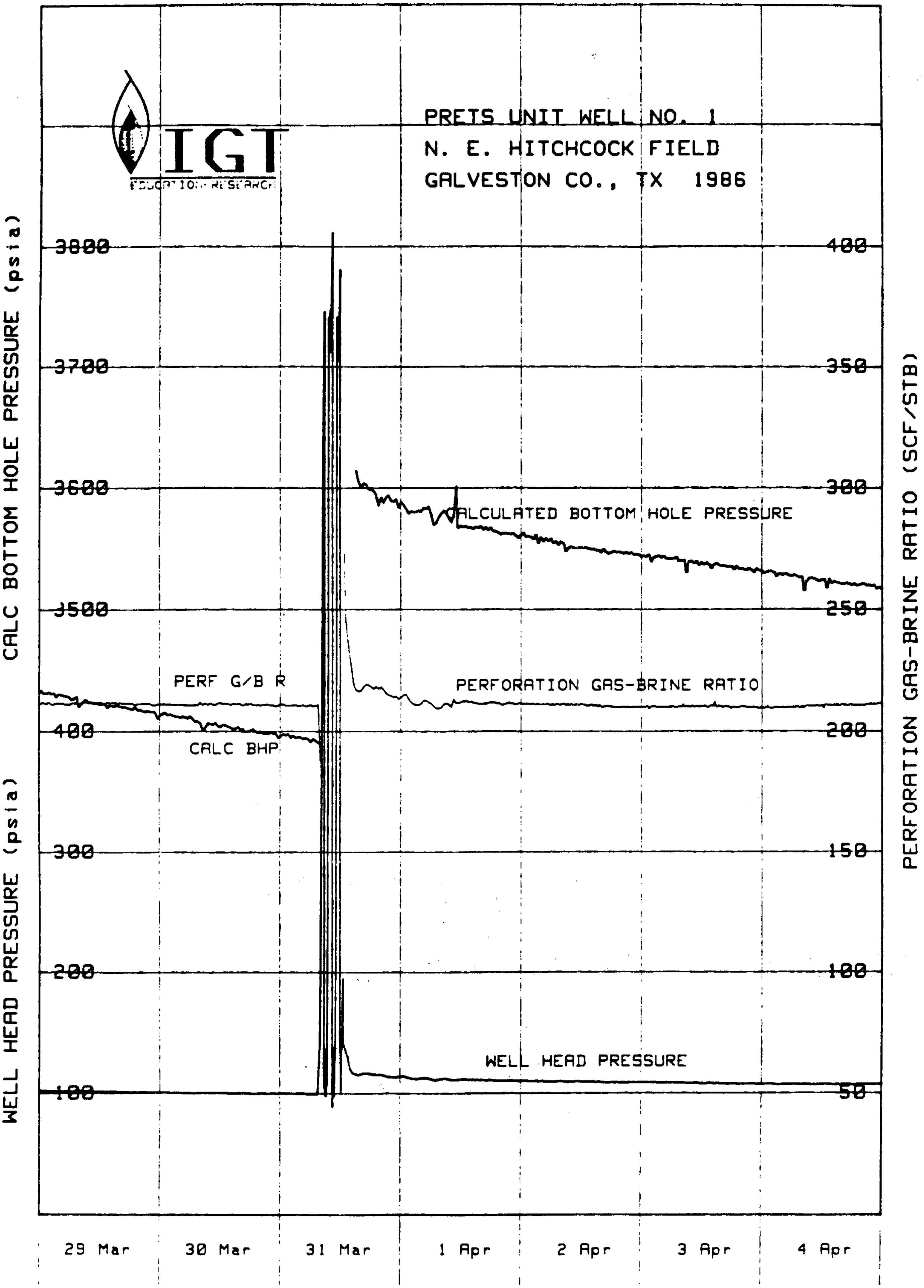
- Collect Production Data
- Collect & Analyses Produced Fluids & Solids
- Intrerpret Above Results in Terms of Reservoir and Surface Equipment Preformance
- Make Information Available to GRI Contractors, Field Operators and the Gas Industry

Major Accomplishments From GRI Participation:

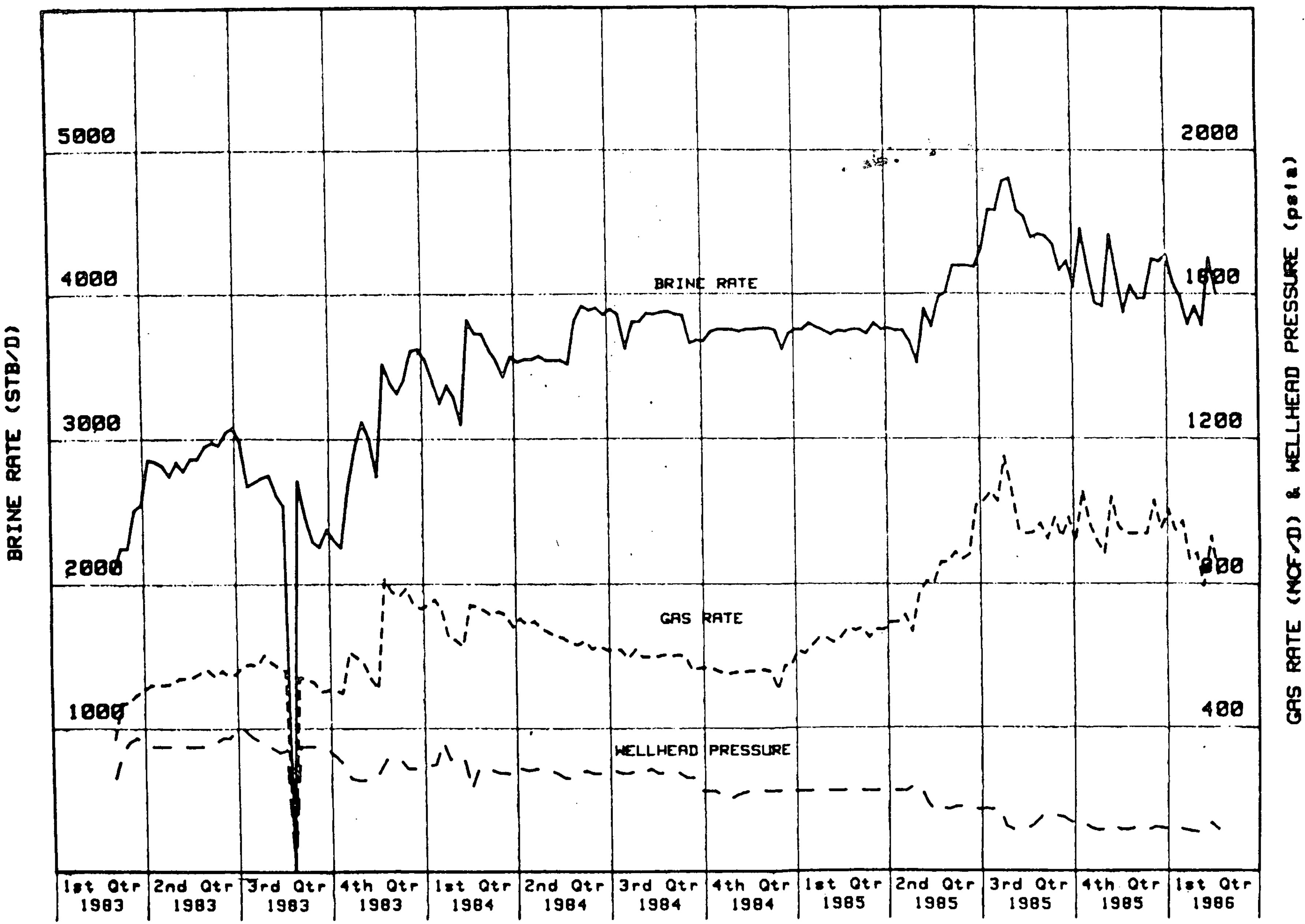
- Established a routine of weekly distribution of production data to Project Participants
- Achieved operation of the borrowed three-phase separator with reduced Prets wellhead pressure
- Identified two-week cycles in Prets gas production
- Developed a cost effective routine for acid removal of scale
- Increased Prets oil recovery by about 20 percent
- Increased Thompson gas production by 50 percent
- Identified Iron Hydroxides as a major problem in the brine disposal well and implemented a gas blanket proceedure to preclude their formation



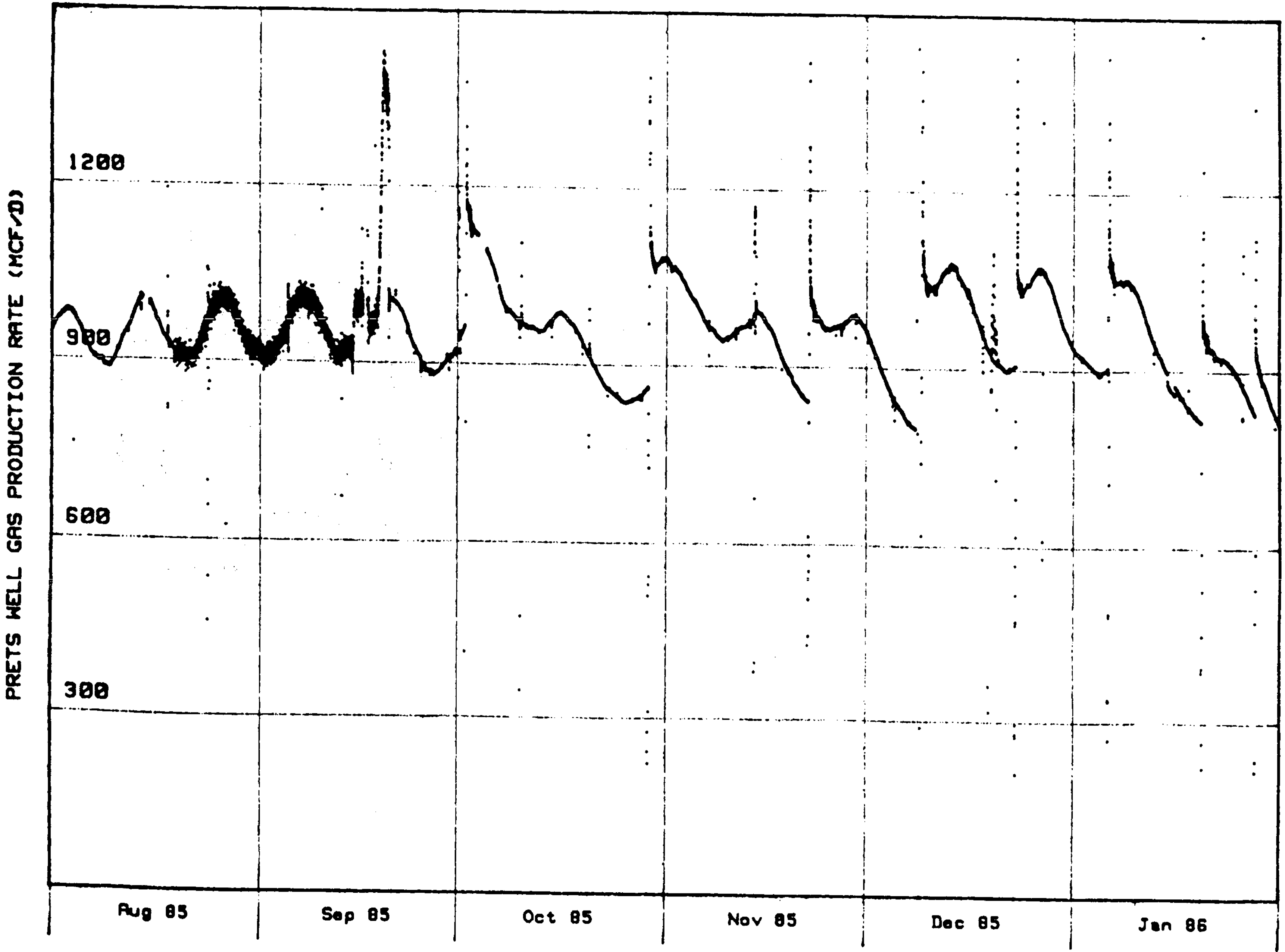
IGT
EDUCATION-RESEARCH
PRETS UNIT WELL NO. 1
N. E. HITCHCOCK FIELD
GALVESTON CO., TX 1986
BRINE RATE (STB/D)
GAS RATES (MCF/D)
6000
5000
4000
3000
2000
1000
0
1600
1400
1200
1000
800
600
400
200
BRINE RATE
BRINE RATE
PERFORATION GAS RATE
PERFORATION GAS RATE
SALES GAS RATE
SALES GAS RATE
29 Mar
30 Mar
31 Mar
1 Apr
2 Apr
3 Apr
4 Apr



PRETS UNIT WELL NO. 1
N. E. HITCHCOCK FIELD
GALVESTON CO., TX 1986
IGT
EDUCATION·RESEARCH
CALC BOTTOM HOLE PRESSURE (psia)
WELL HEAD PRESSURE (psia)
PERFORATION GAS-BRINE RATIO (SCF/STB)
3800
3700
3600
3500
400
300
200
100
400
350
300
250
200
150
100
50
CALCULATED BOTTOM HOLE PRESSURE
PERF G/B R
PERFORATION GAS-BRINE RATIO
CALC BHP
WELL HEAD PRESSURE
29 Mar
30 Mar
31 Mar
1 Apr
2 Apr
3 Apr
4 Apr



BRINE RATE (STB/D)
GAS RATE (MCF/D) & WELLHEAD PRESSURE (psia)
5000
4000
3000
2000
1000
2000
1600
1200
800
400
BRINE RATE
GAS RATE
WELLHEAD PRESSURE
1st Qtr 1983
2nd Qtr 1983
3rd Qtr 1983
4th Qtr 1983
1st Qtr 1984
2nd Qtr 1984
3rd Qtr 1984
4th Qtr 1984
1st Qtr 1985
2nd Qtr 1985
3rd Qtr 1985
4th Qtr 1985
1st Qtr 1986



PRETS WELL GAS PRODUCTION RATE (MCF/D)
1200
900
600
300
Aug 85
Sep 85
Oct 85
Nov 85
Dec 85
Jan 86

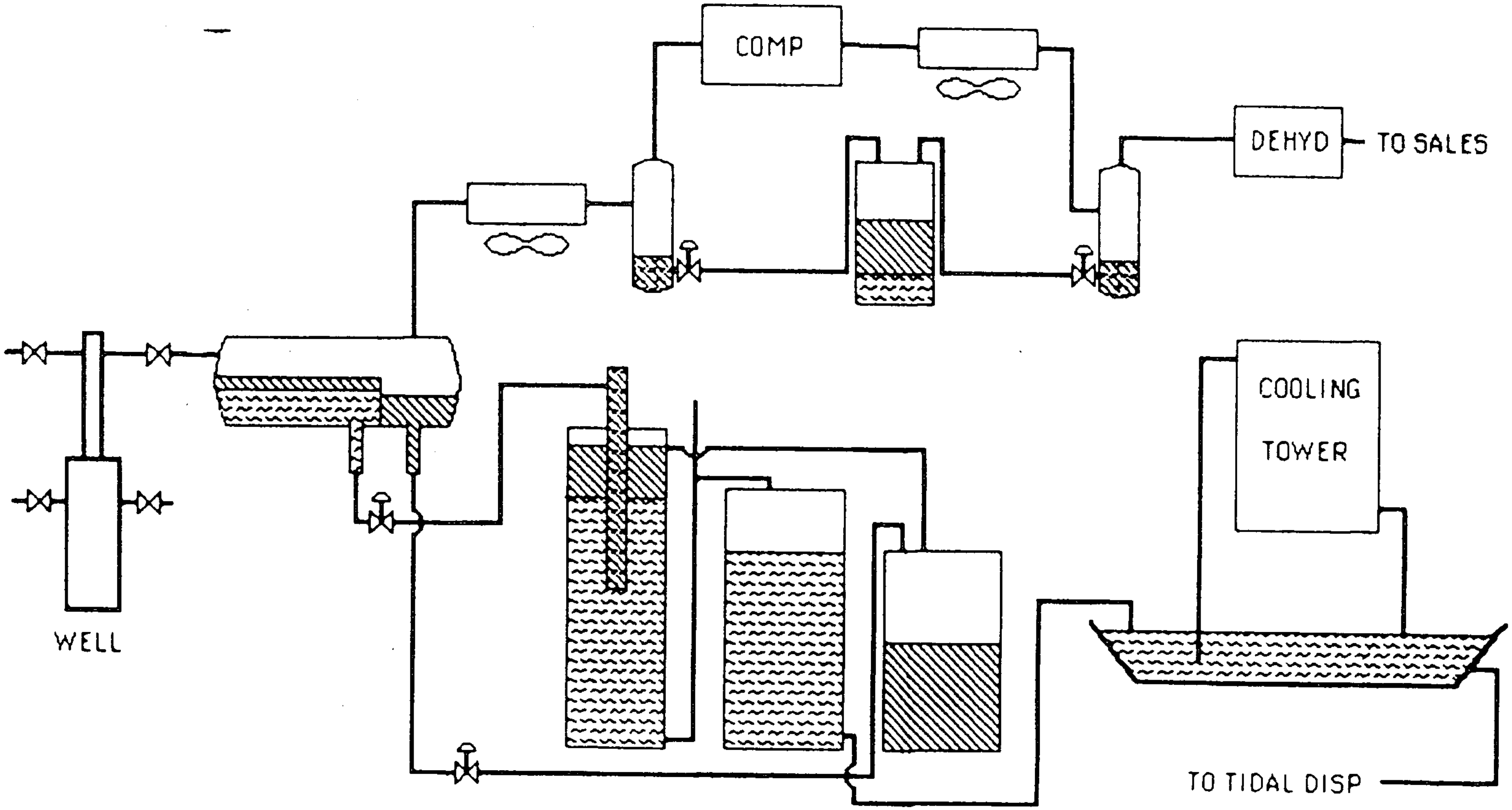


Figure 2: Prets Well Surface Facilities

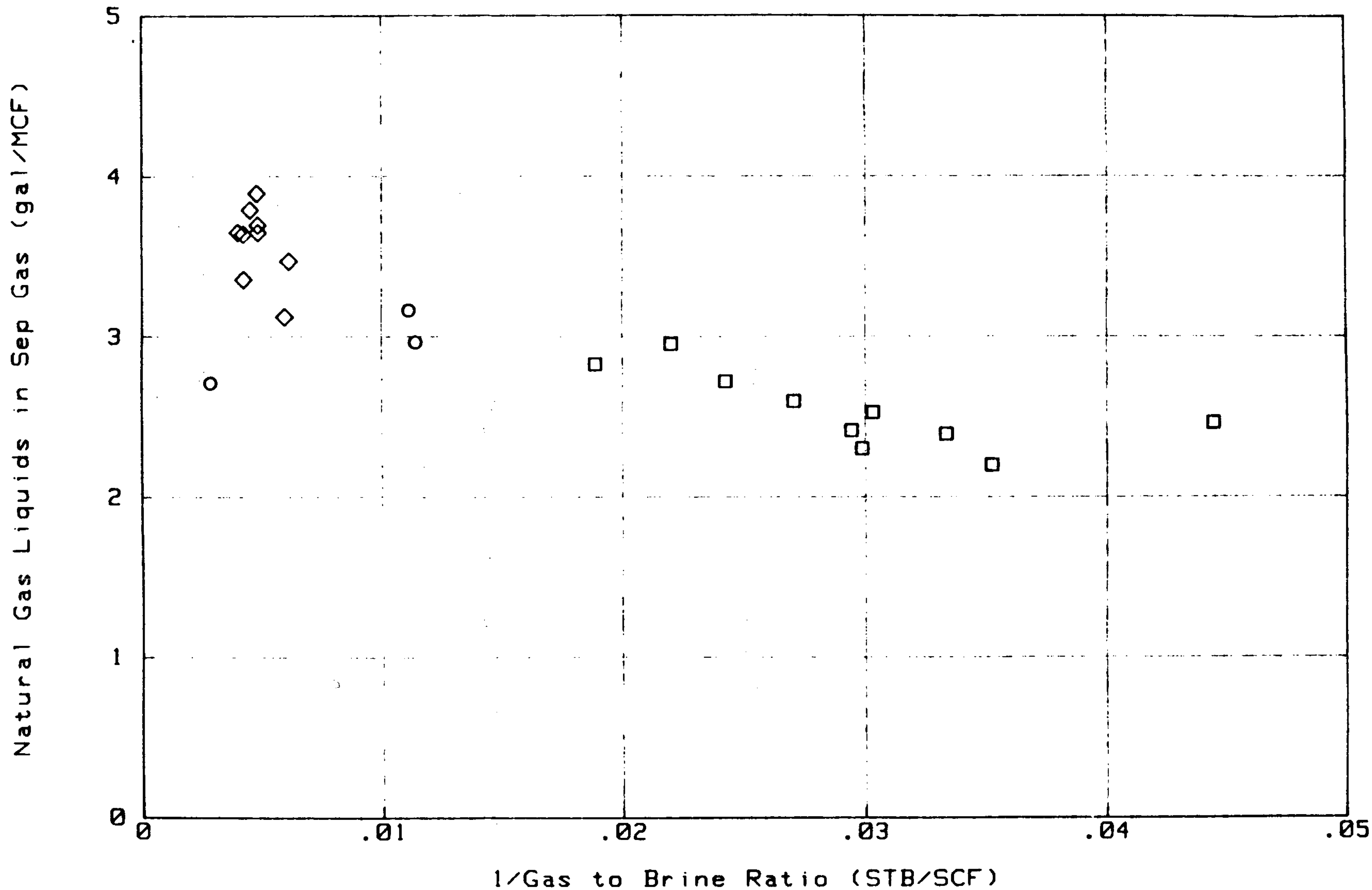


Figure 2. NGL Content of Separator Gas Versus 1/GBR

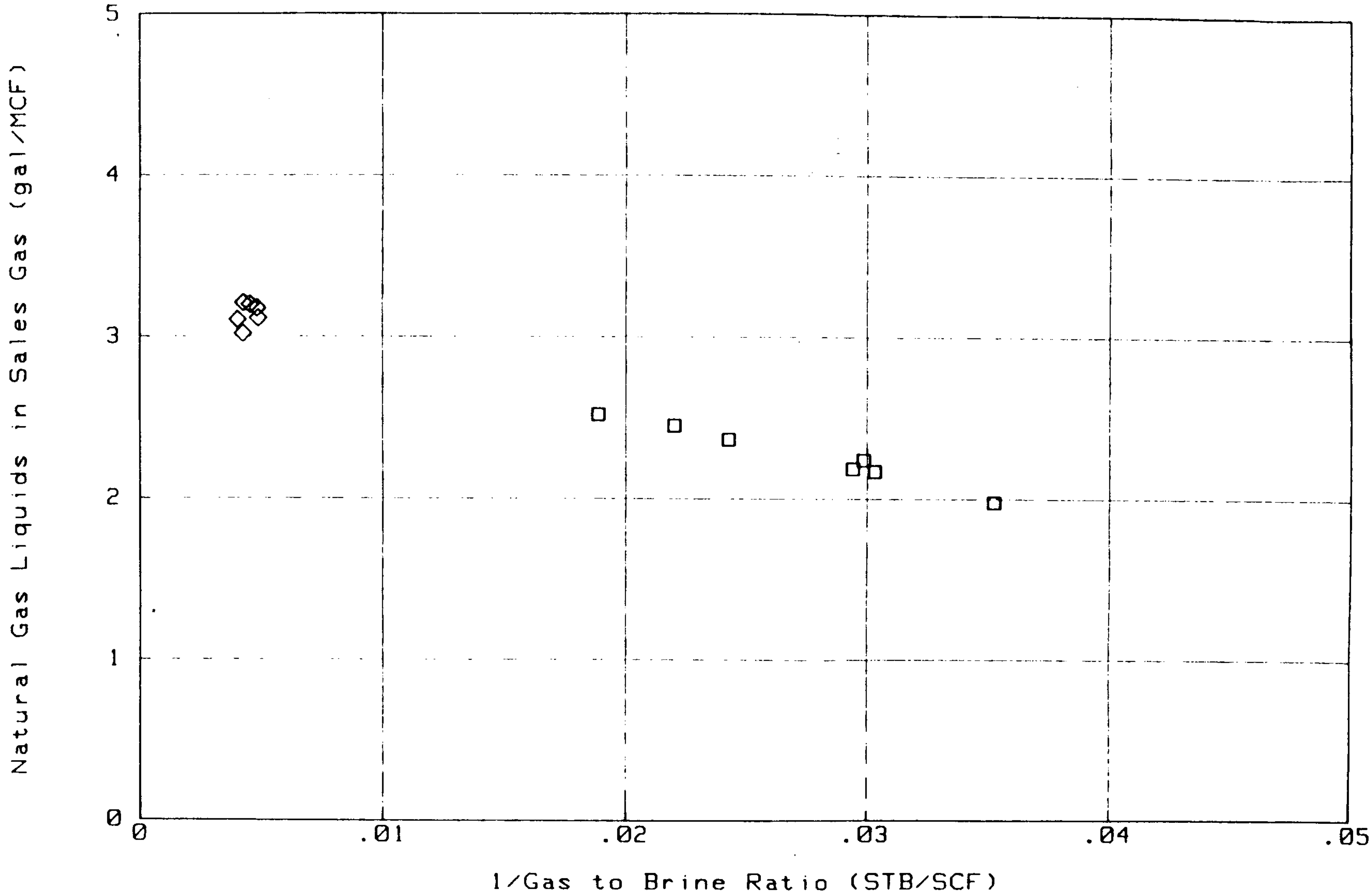
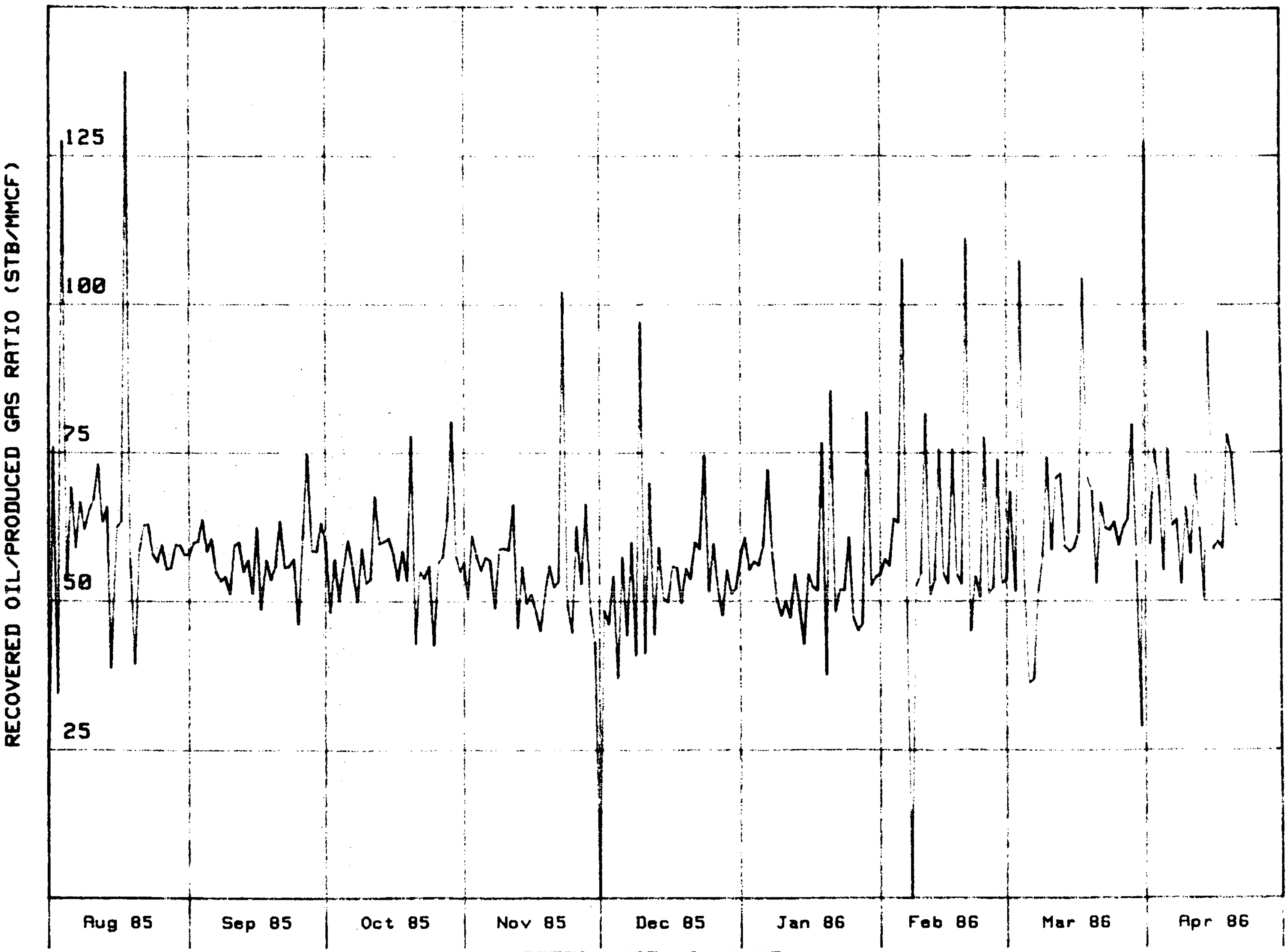
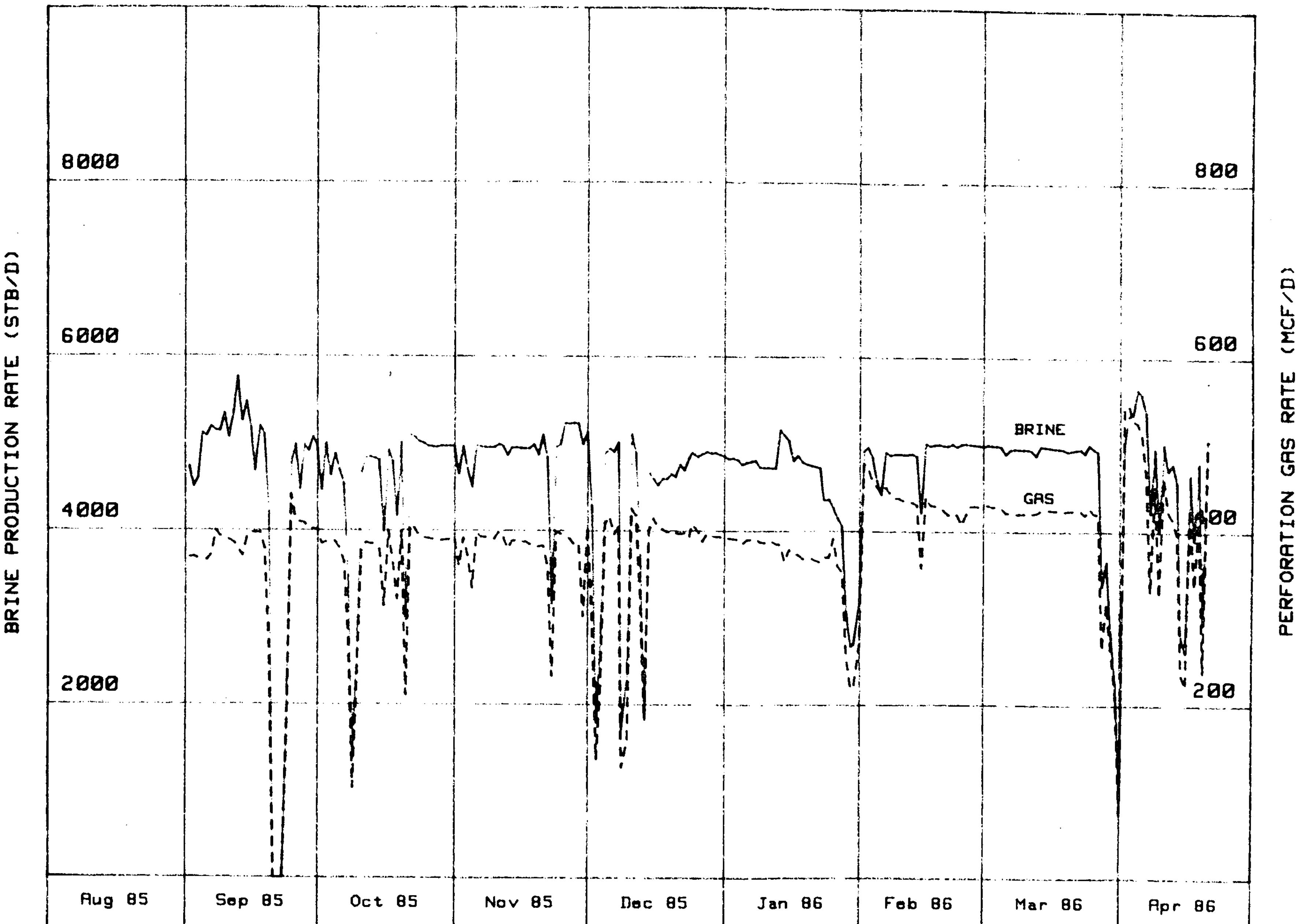


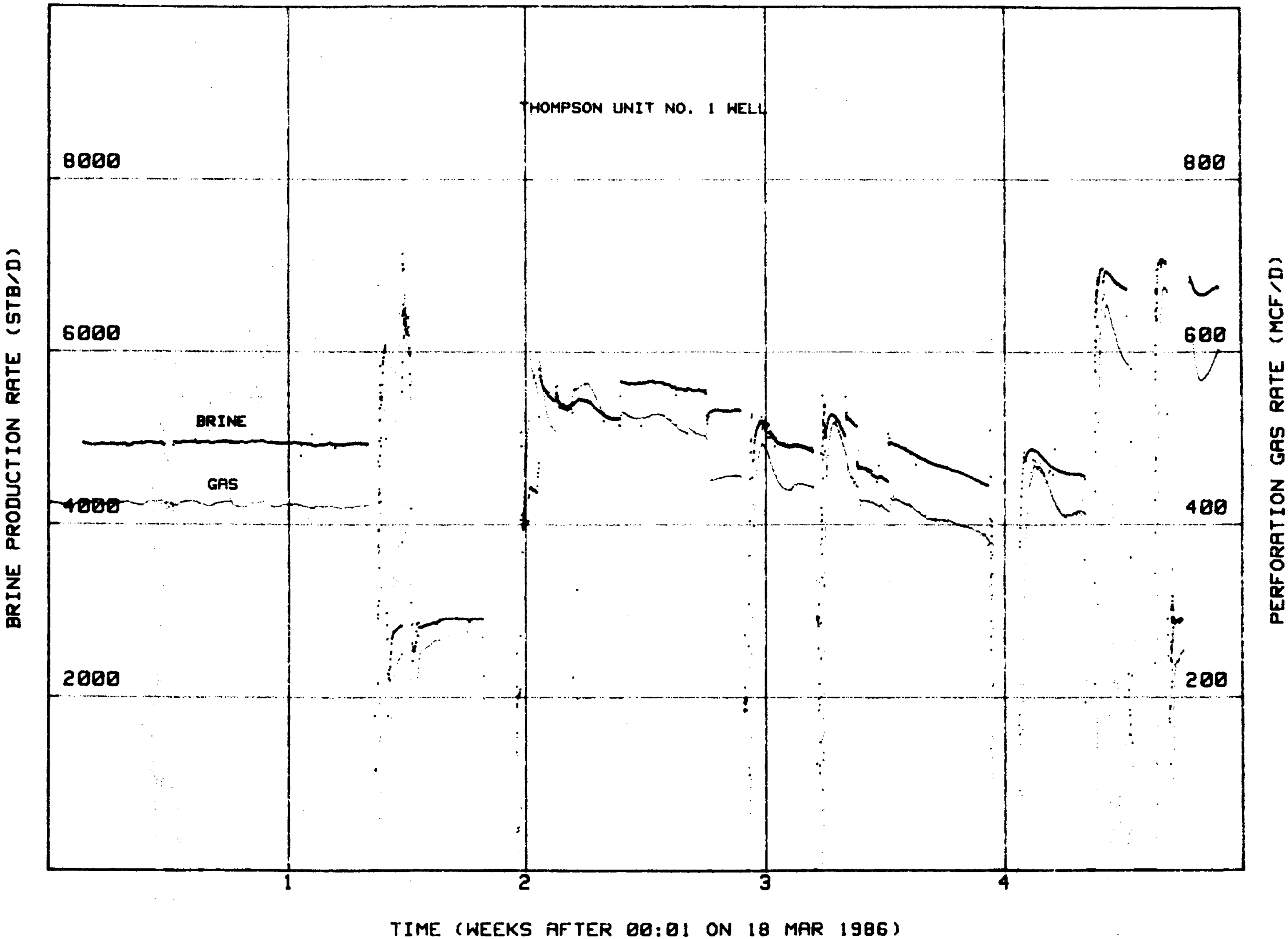
Figure 3. NGL Content of Sales Gas Versus 1/GBR



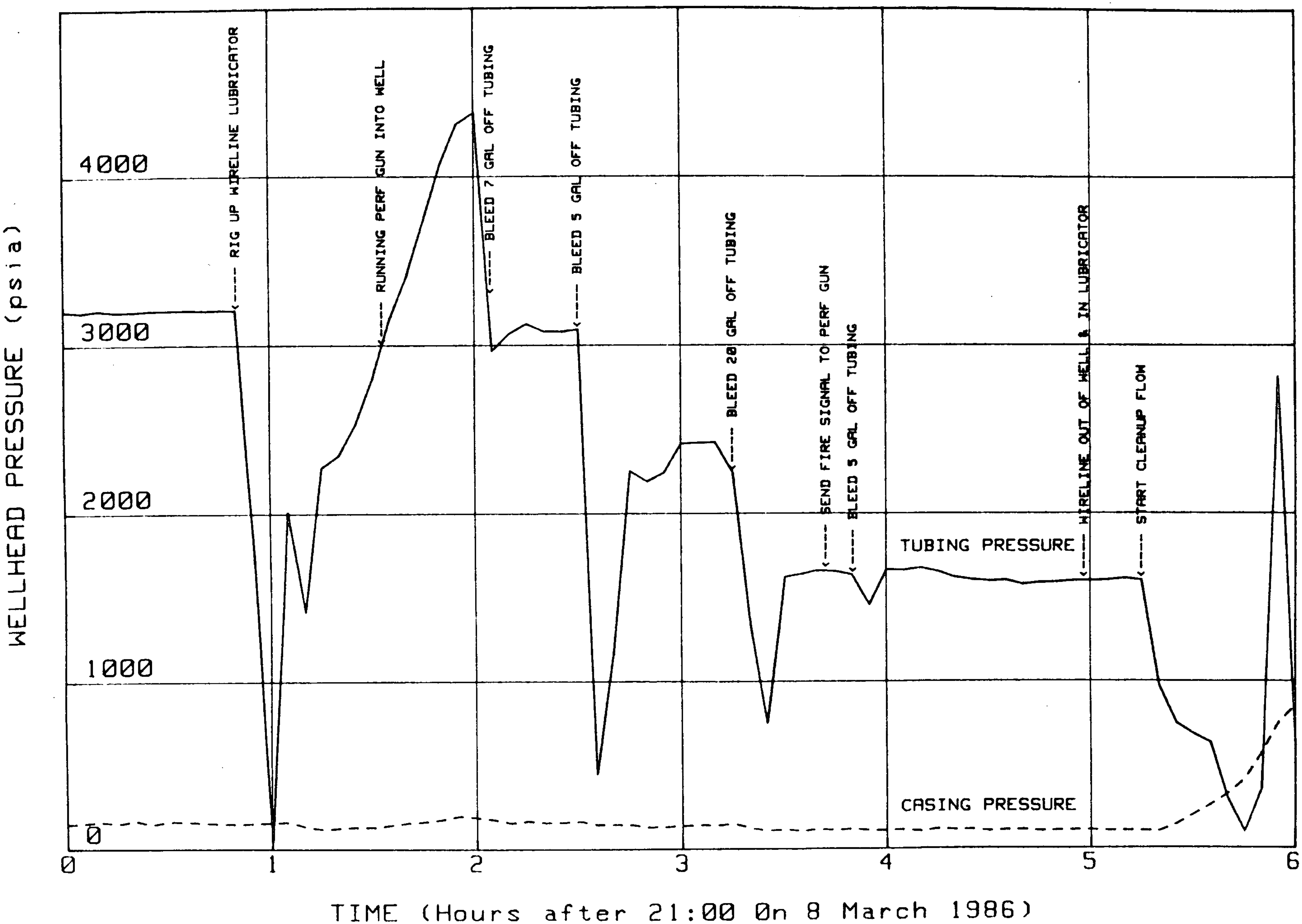
PRETS UNIT NO. 1 WELL



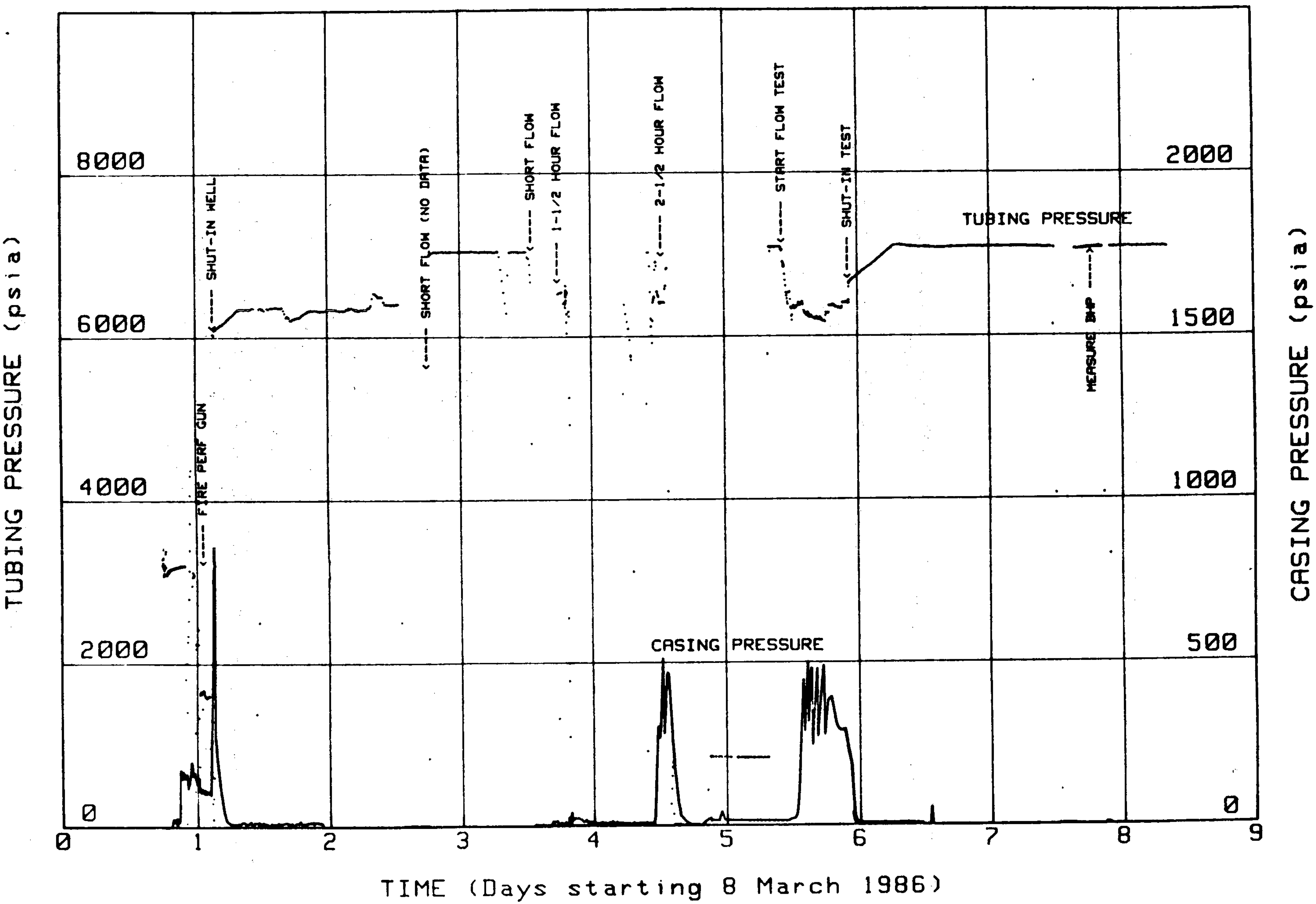
THOMPSON UNIT NO. 1 WELL



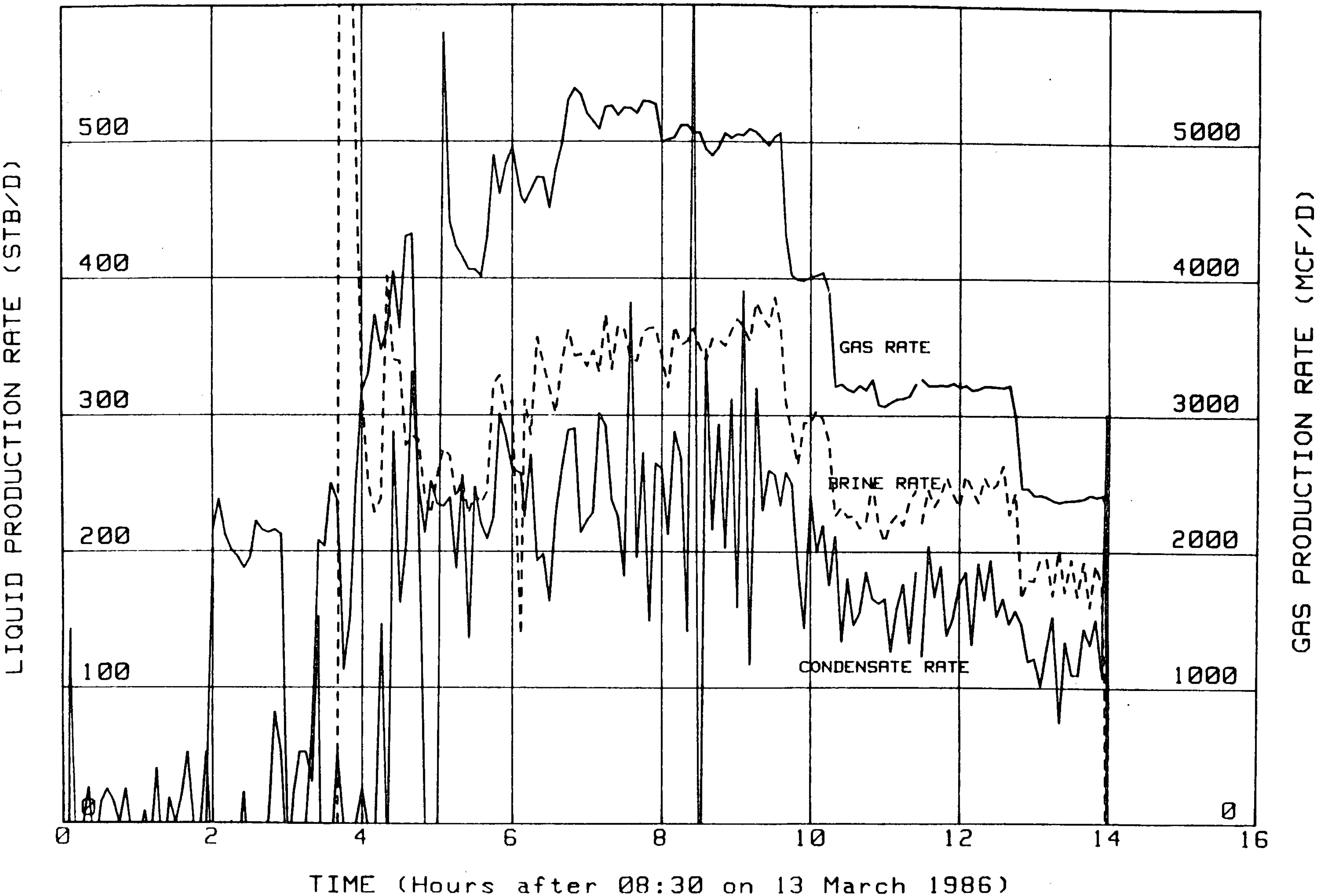
THOMPSON UNIT NO. 1 WELL
BRINE
GAS
8000
6000
4000
2000
800
600
400
200
1
2
3
4
BRINE PRODUCTION RATE (STB/D)
PERFORATION GAS RATE (MCF/D)
TIME (WEEKS AFTER 00:01 ON 18 MAR 1986)



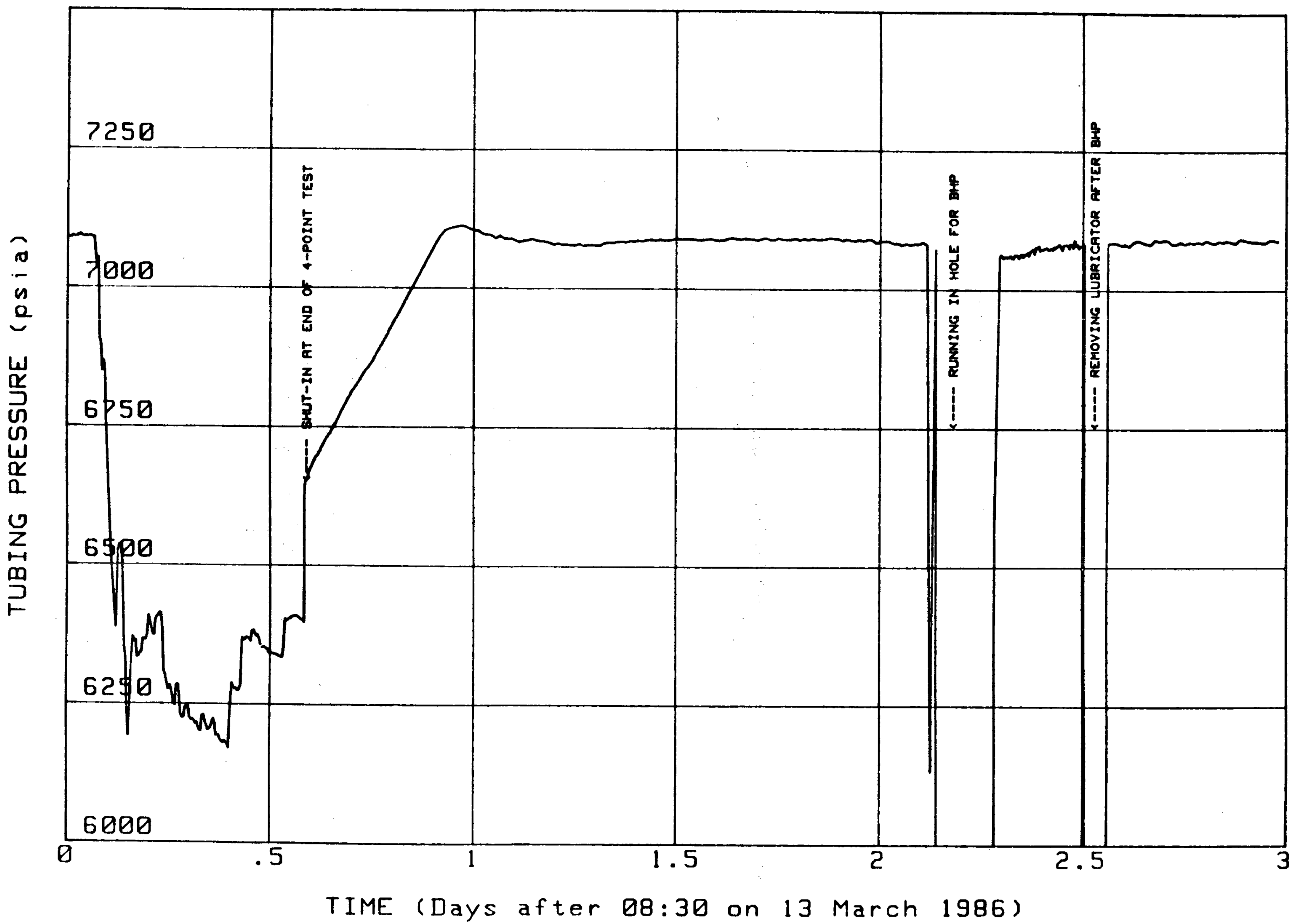
WELLHEAD PRESSURE (psia)
4000
3000
2000
1000
0
RIG UP WIRELINE LUBRICATOR
RUNNING PERF GUN INTO WELL
BLEED 7 GAL OFF TUBING
BLEED 5 GAL OFF TUBING
BLEED 20 GAL OFF TUBING
SEND FIRE SIGNAL TO PERF GUN
BLEED 5 GAL OFF TUBING
WIRELINE OUT OF WELL & IN LUBRICATOR
START CLEANUP FLOW
TUBING PRESSURE
CASING PRESSURE
0
1
2
3
4
5
6
TIME (Hours after 21:00 On 8 March 1986)



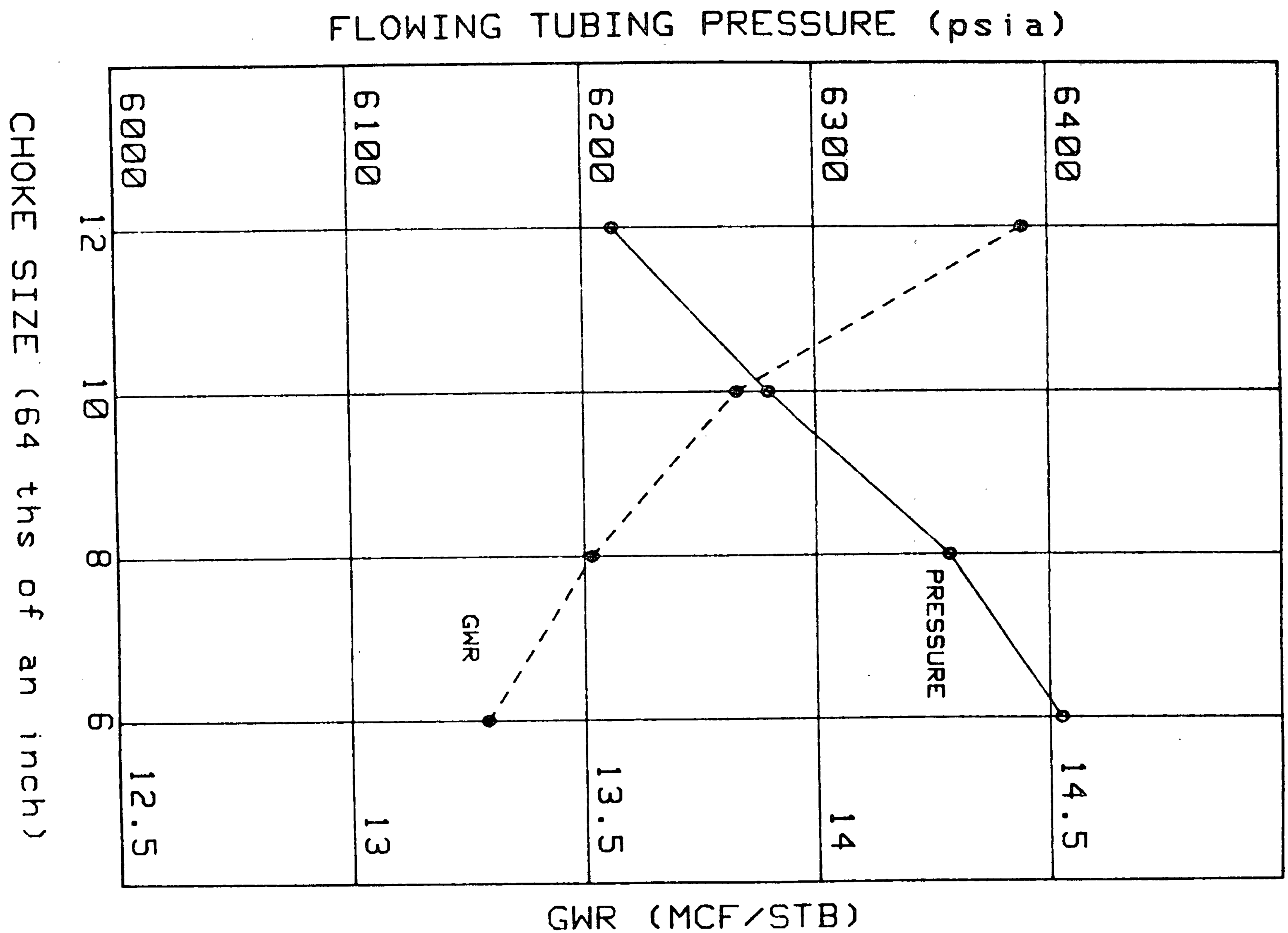
TUBING PRESSURE (psia)
CASING PRESSURE (psia)
8000
6000
4000
2000
0
2000
1500
1000
500
0
SHUT-IN WELL
FIRE PERF GUN
SHORT FLOW (NO DATA)
SHORT FLOW
1-1/2 HOUR FLOW
2-1/2 HOUR FLOW
START FLOW TEST
SHUT-IN TEST
TUBING PRESSURE
MEASURE BHP
CASING PRESSURE
0
1
2
3
4
5
6
7
8
9
TIME (Days starting 8 March 1986)



500
400
300
200
100
0
5000
4000
3000
2000
1000
0
LIQUID PRODUCTION RATE (STB/D)
GAS PRODUCTION RATE (MCF/D)
GAS RATE
BRINE RATE
CONDENSATE RATE
0
2
4
6
8
10
12
14
16
TIME (Hours after 08:30 on 13 March 1986)



7250
7000
6750
6500
6250
6000
TUBING PRESSURE (psia)
0
.5
1
1.5
2
2.5
3
TIME (Days after 08:30 on 13 March 1986)
<---- SHUT-IN AT END OF 4-POINT TEST
<---- RUNNING IN HOLE FOR BHP
<---- REMOVING LUBRICATOR AFTER BHP



FLOWING TUBING PRESSURE (psia)
6000
6100
6200
6300
6400
CHOKE SIZE (64 ths of an inch)
12
10
8
6
GWR
PRESSURE
12.5
13
13.5
14
14.5
GWR (MCF/STB)

S. APPENDIX 19

MODELING RESULTS FOR N.E. HITCHCOCK

K. ANCELL - DF&A

EVALUATION AND MODELING
OF
CO-PRODUCTION RESERVOIRS

NUMERICAL MODEL
OF
NORTHEAST HITCHCOCK FIELD
(9,100' FRIO SAND)

GRI Contract No. 5085-212-1185

Dowdle Fairchild & Ancell, Inc.

SUMMARY

NORTHEAST HITCHCOCK FIELD
9,100' FRIO SAND

The Northeast Hitchcock Field, located in Galveston County, Texas, produces gas and gas condensate from the Upper Frio (Frio "A") sand, lying at a depth of approximately 9100 feet subsea. Initial reservoir pressure at this depth was 5650 psia. The structure of the producing zone is a northwest plunging anticline, of moderate relief, that is truncated by several down-to-the-coast dipping faults. Porosity and permeability of the pay zone range 18-35 percent and 20-3200 md, respectively. Some 24 wells were drilled to exploit the reservoir with twelve of these wells completed as producers. To 1/1/86 (first production 1958), some 88.0 Bcf of gas and 5209 Mbbls of condensate have been produced. Original gas and condensate in place are estimated to be 131.8 Bcf and 12440 Mbbl. Primary production was hampered by water encroachment with all but one well "watered-out" by the mid-seventies.

In 1982, Secondary Gas Recovery (SGR) began a co-production project to improve gas recoveries by producing large volumes of water. Two re-entries of previously abandoned producers and two new wells were part of the project. While performance to date has been promising, the project has been hampered with many operational problems.

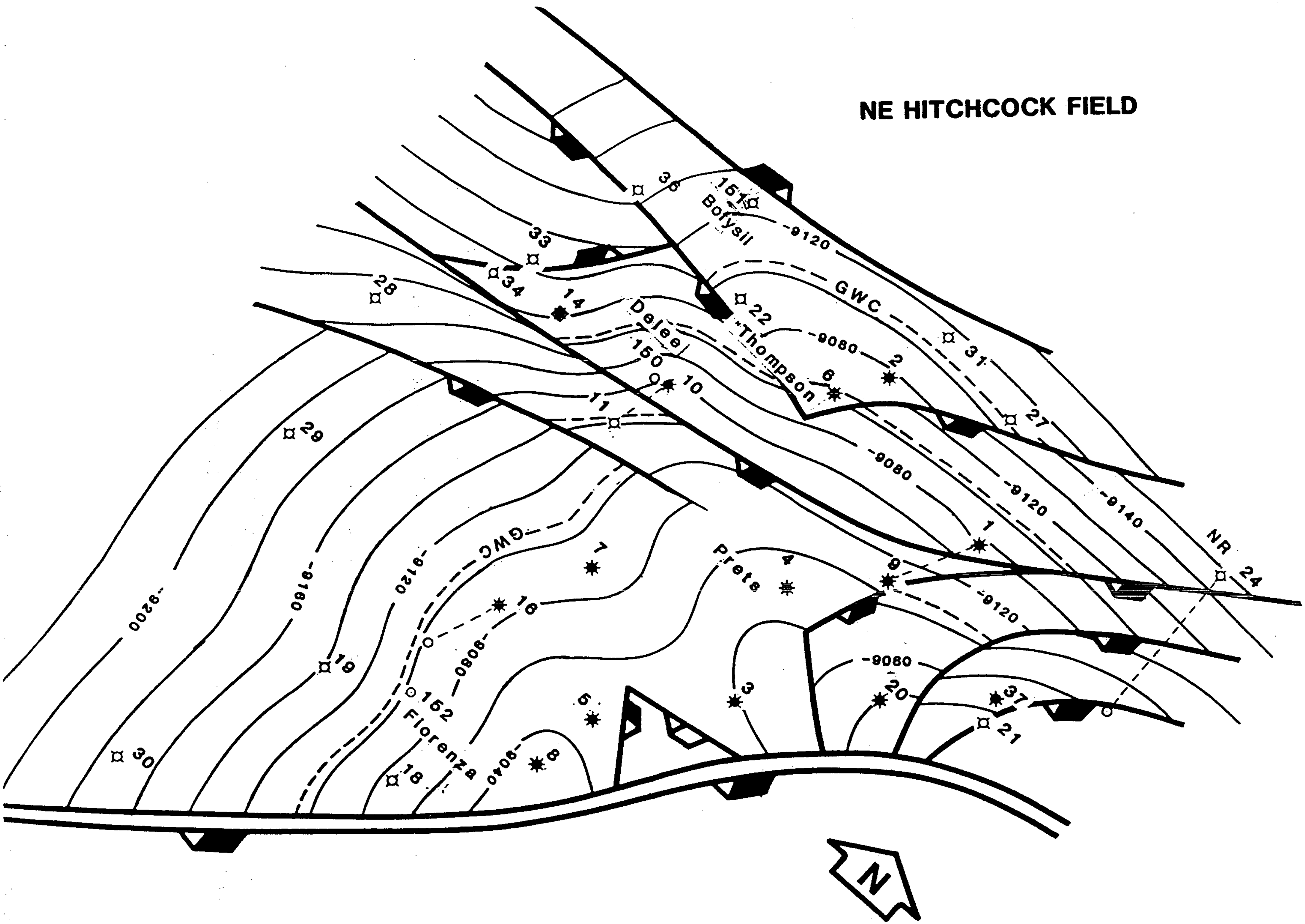
One of the prime considerations of co-production is to be able to project the optimum schedule of gas and water production and number of producing wells in order to optimize profits. Numerical simulation offers a way to help identify and determine the relative significance of the controlling factors considered in developing the optimum co-production plan. Dowdle Fairchild & Ancell, Inc. (DFA) has developed a reservoir simulation model of the Northeast Hitchcock Field based on the geologic description prepared by the Bureau of Economic Geology and Eaton Operating Company, along with other basic reservoir rock and fluid data and performance history. The reservoir simulation model was "tuned" to match the Northeast Hitchcock historical performance through the history match process. The history matched model was then used to make the performance projection as described below.

During the "history match" phase of a reservoir model development, historical rates, either gas or water, are specified and the alternate phase is calculated based on the relative mobility of this phase to the specified phase. In making predictions, rate control is affected by specifying tubing head pressures and the model calculates the appropriate gas and water volumes. For this procedure, we have utilized the multi-phase vertical pressure-drop procedure developed by IGT for GRI, based on actual Northeast Hitchcock data.

Results of three base predictions and two alternate predictions are presented. Case 1 and Case 1A produced the Prets and Thompson wells (2 wells). Case 2 and Case 2A produced the Huff-A, Prets, Thompson, Delee and Lemm wells (5 wells). Case 3 produced the Huff-A, Prets and Thompson wells (3 wells). The predicted performance was found to be greatly dependent on having the aquifer (water influx) modeled correctly, utilizing the Carter Tracy influence functions, i.e. the greater the water influx, the smaller the gas rate. Therefore, Case 1A and Case 2A were designed to model the effect of a larger water influx. Each case was run to 1-1-1991. The table below gives the cumulative gas and water produced since 4-1-1986.

		Case 1	Case 1A	Case 2	Case 2A	Case 3
Field Total	Gas	**4165.0**	**3601.3**	**8484.3**	**7188.0**	**5751.5**
	Water	15197.6	16558.5	21217.0	26786.0	16111.5

NE HITCHCOCK FIELD



Northeast Hitchcock Reservoir Parameters

Porosity - - - - - - - - - - - - - - - 30%

Permeability - - - - - - - - - - 1000 md

Initial Pressure - - - - - - - 5650 psia

Connate Water Saturation - - - - 25%

Residual Gas Saturation - - - - 23.5%

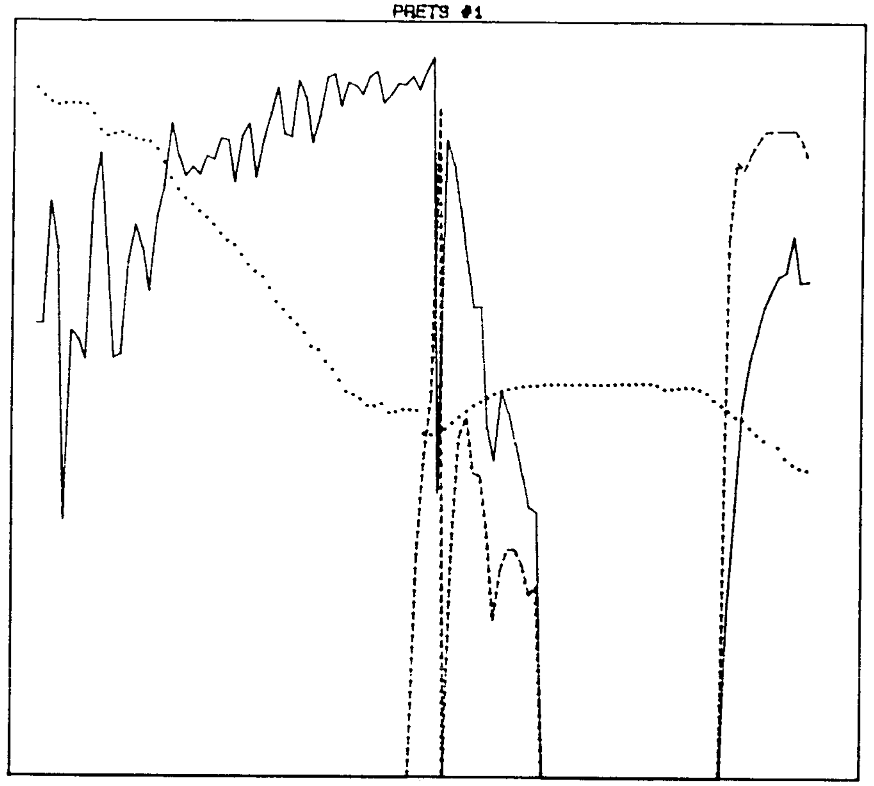
Sol'n Gas at Pi - - - - - - - -17 Scf/bbl

Carter-Tracy Influx

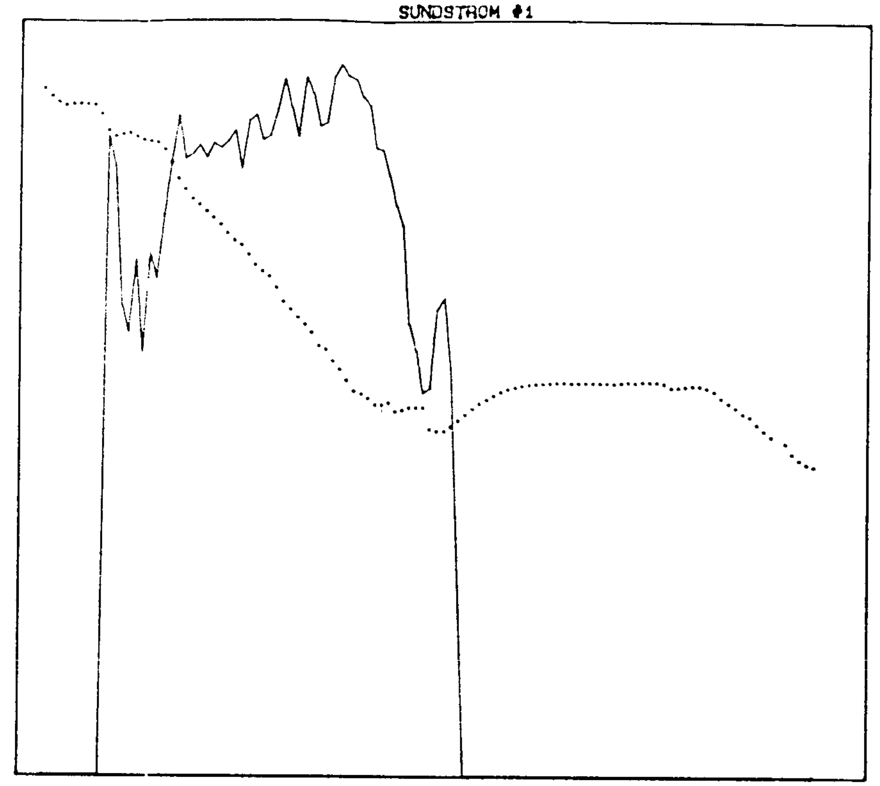
- Dt_D - - - - - - - - - - 0.05 1/days
- B - - - - - - - - - - - - - 42 bbl/day
- Ra/Rr - - - - - - - - - - - - - - - 10

NORTHEAST HITCHCOCK HISTORY MATCH

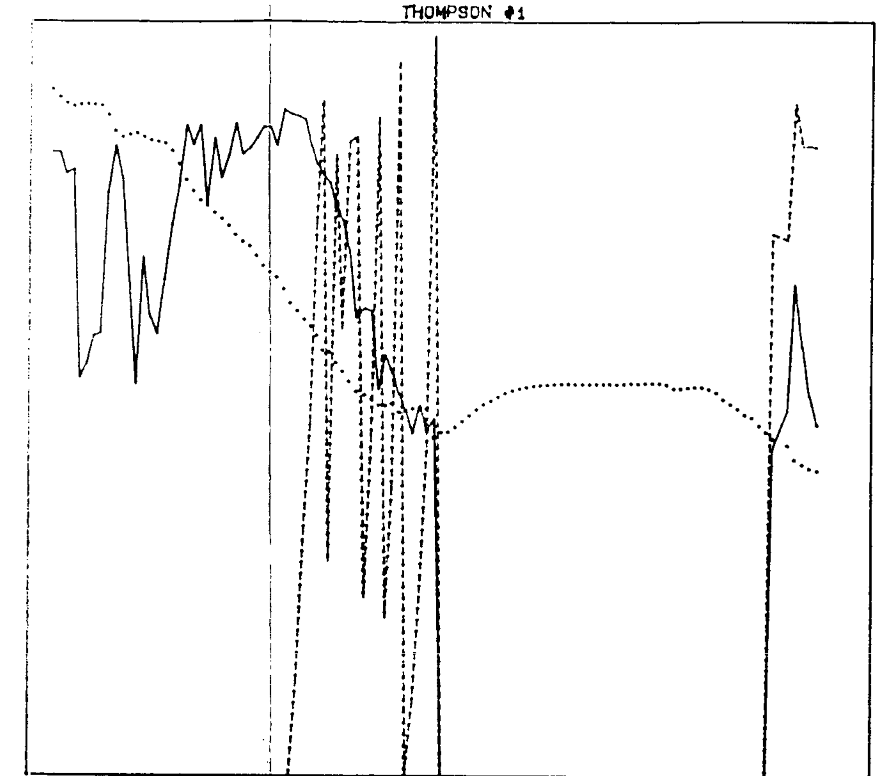
PRETS #1



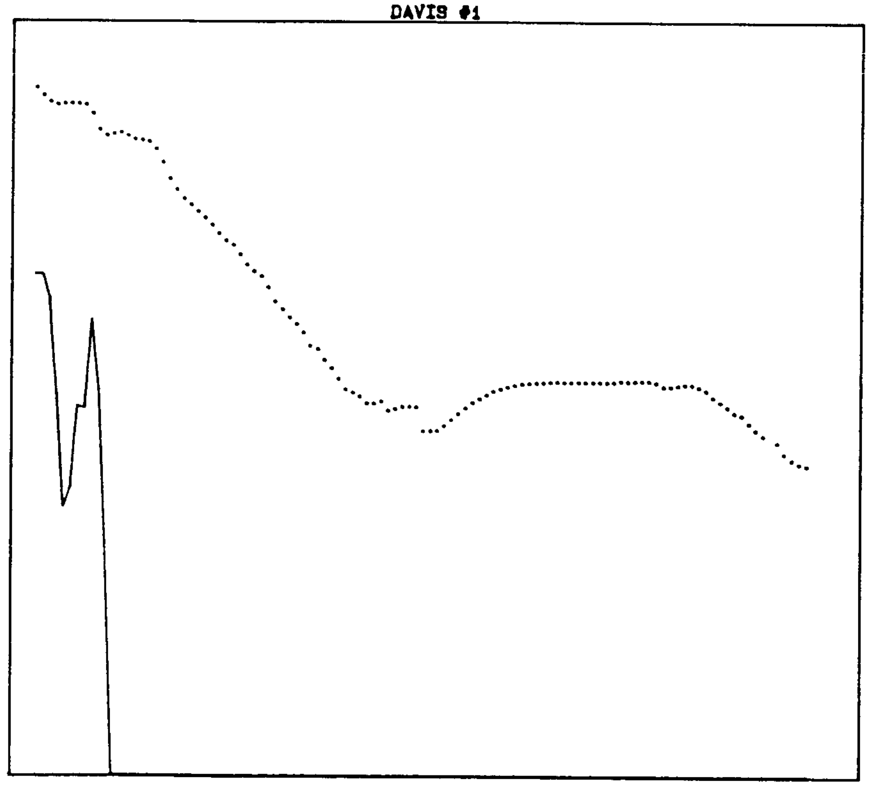
SUNDSTROM #1



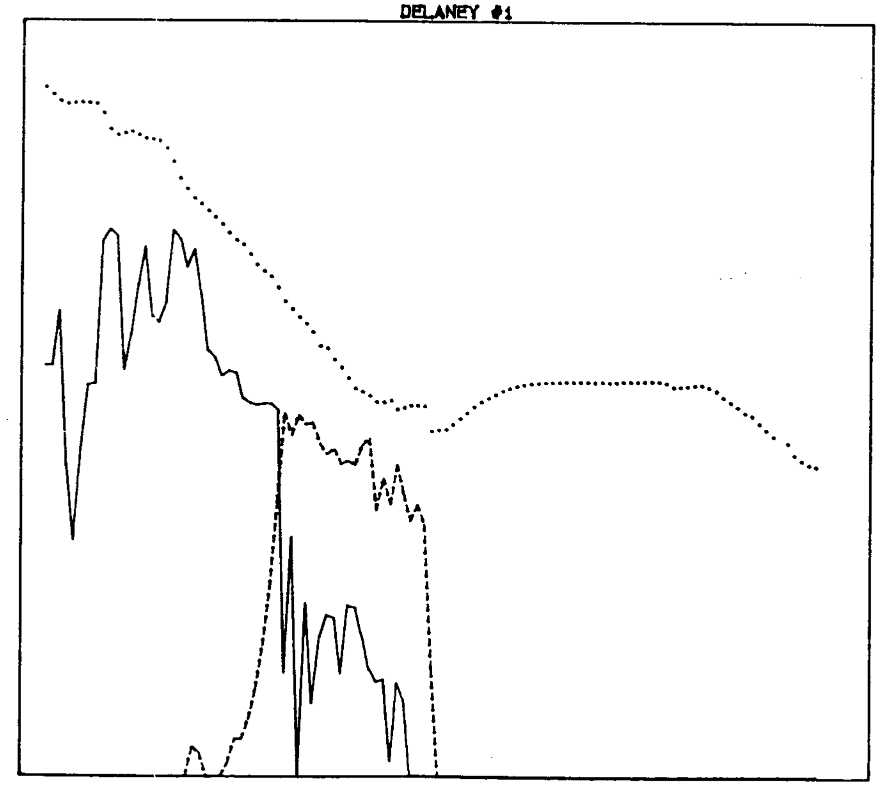
THOMPSON #1



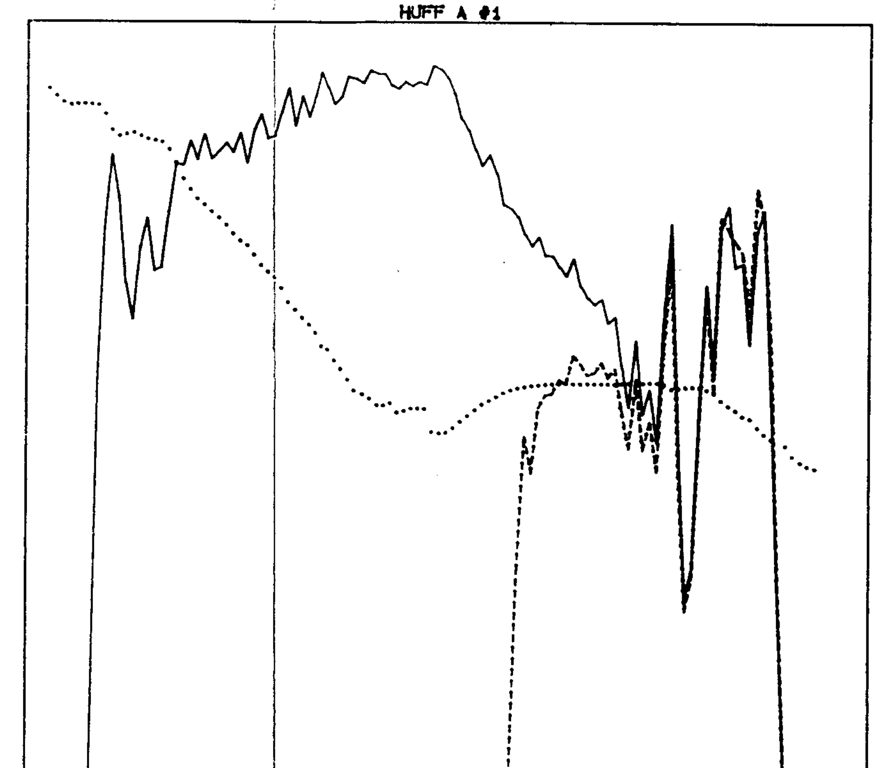
DAVIS #1



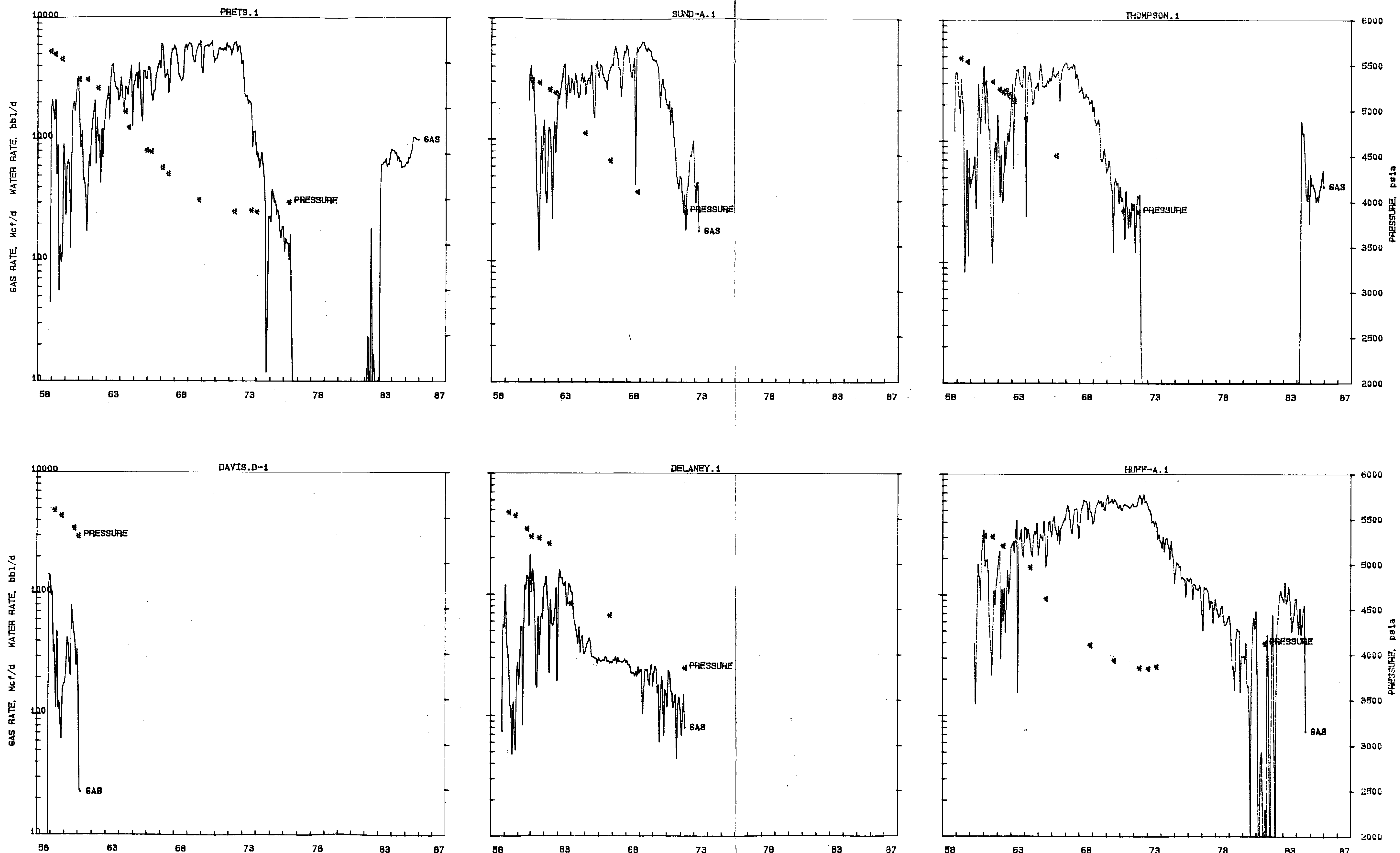
DELANEY #1



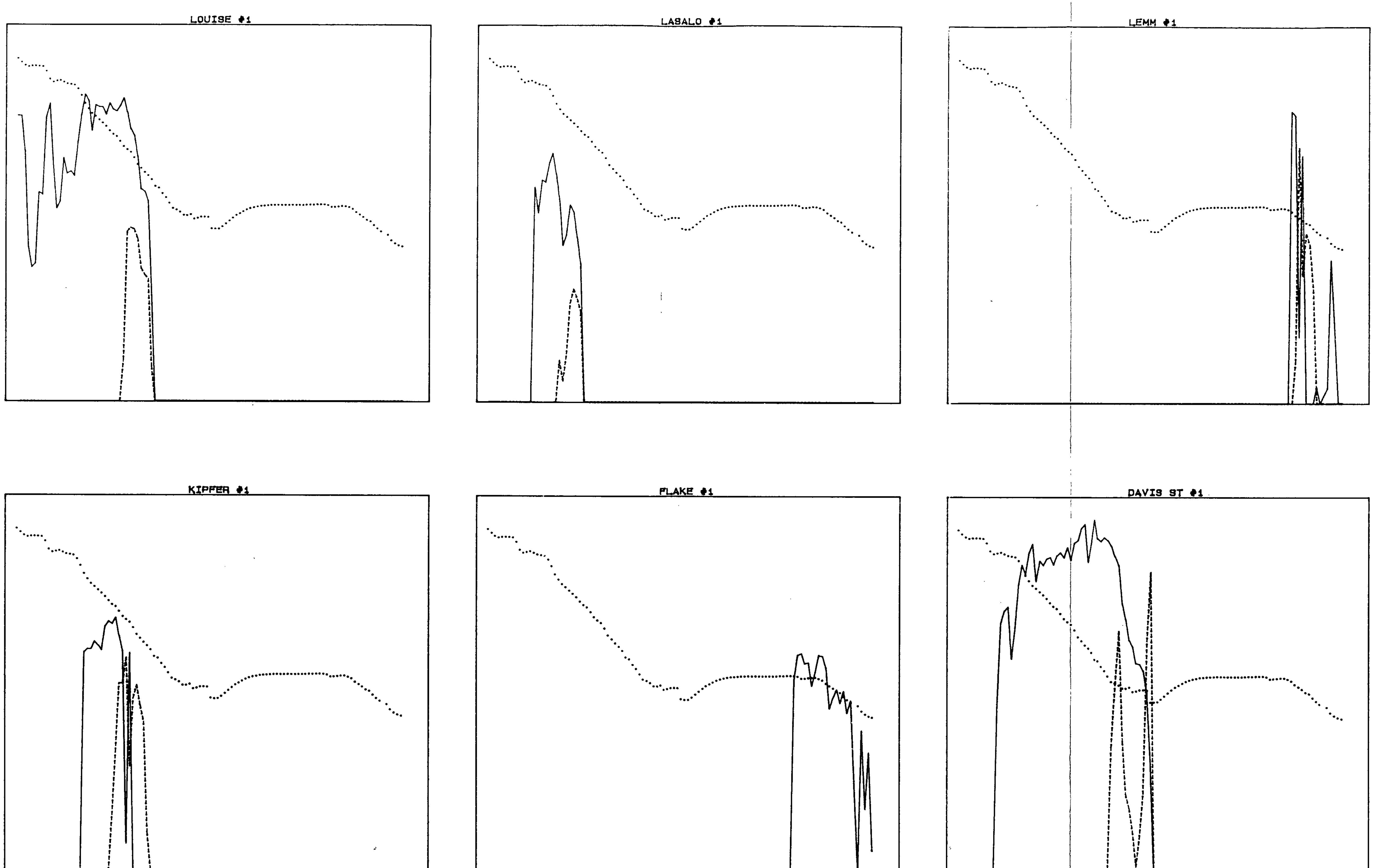
HUFF A #1



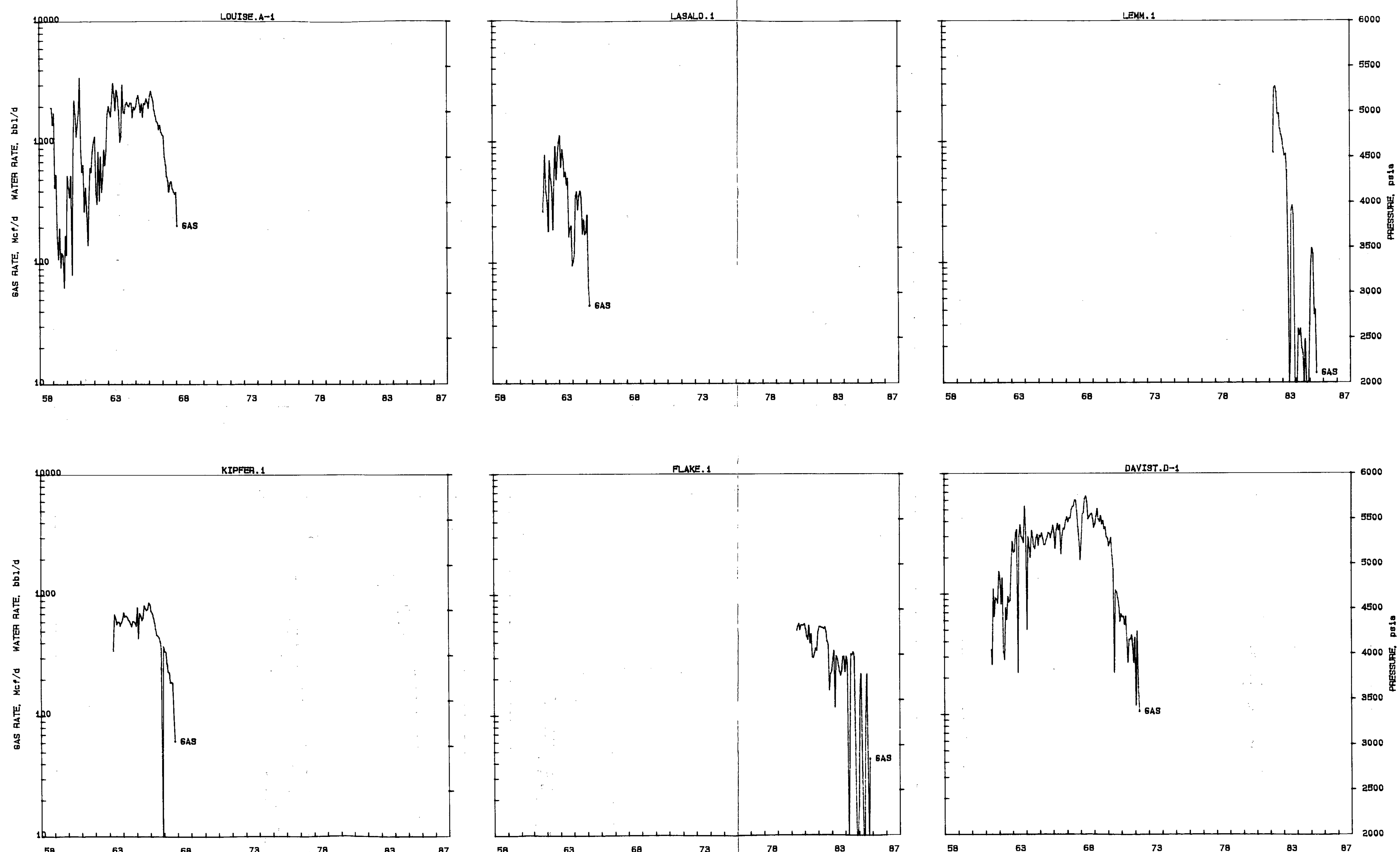
NE HITCHCOCK WELL PRODUCTION



NORTHEAST HITCHCOCK HISTORY MATCH



NE HITCHCOCK WELL PRODUCTION



Northeast Hitchcock
Resource Base

Initial Gas in Place

Free - - - - - - - - - 124.4 Bcf

Solution - - - - - - - - - 7.4 Bcf

Cum. Prod 1-1-1986 - - - 88.0Bcf

Remaining Gas in Place

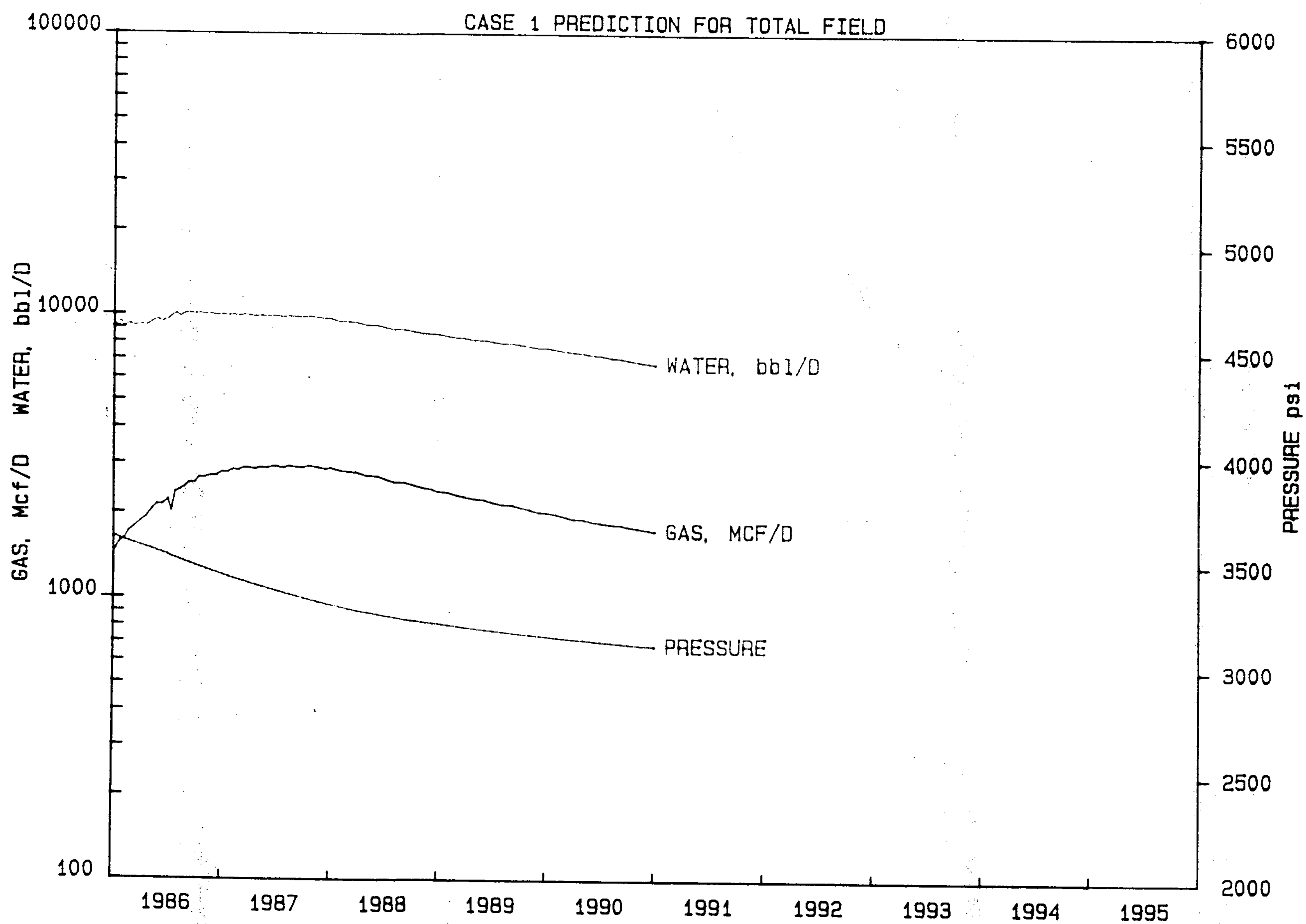
Free - - - - - - - - - - 37.9 Bcf

Solution - - - - - - - - - 6.9 Bcf

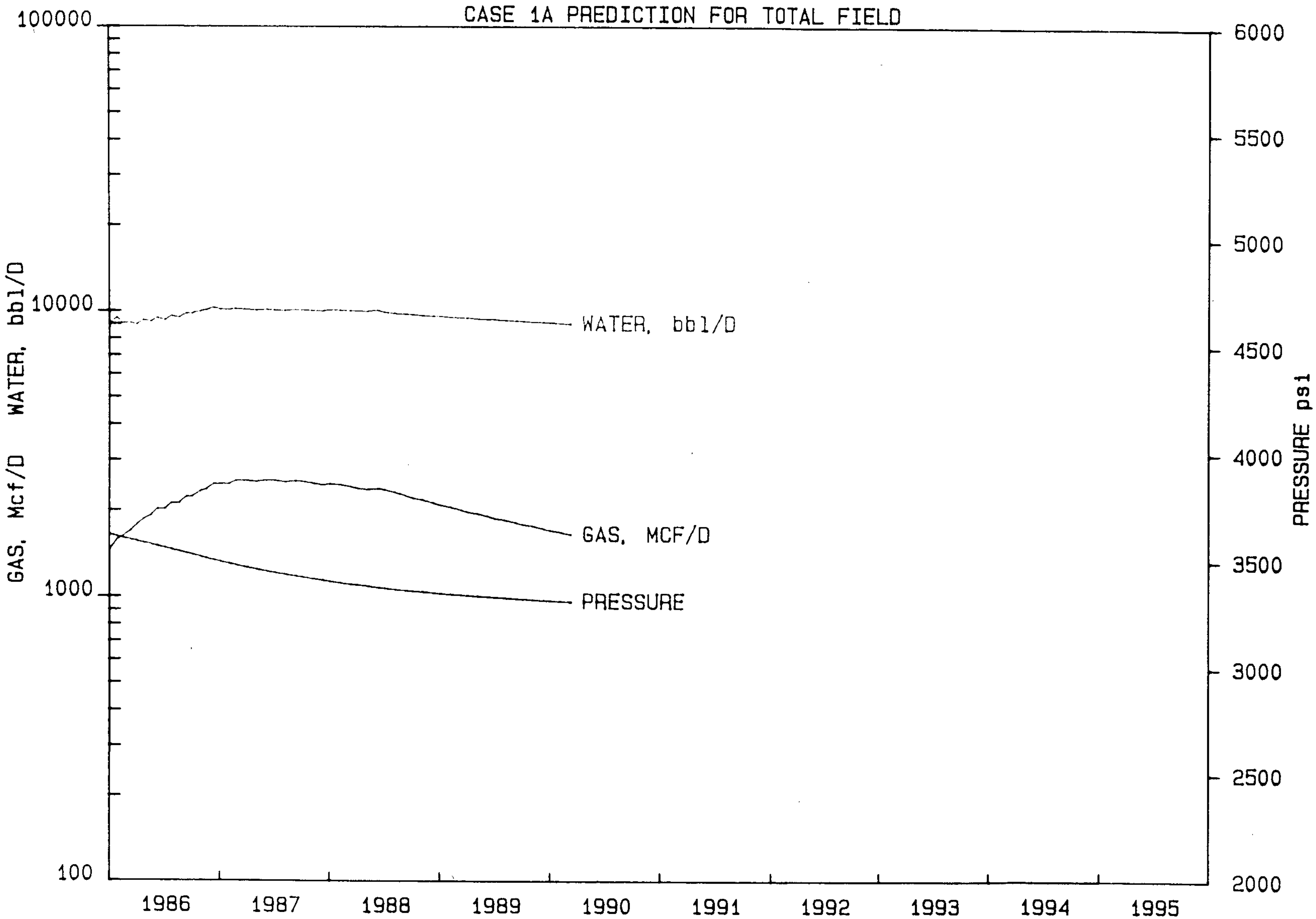
Northeast Hitchcock

PREDICTION CASES

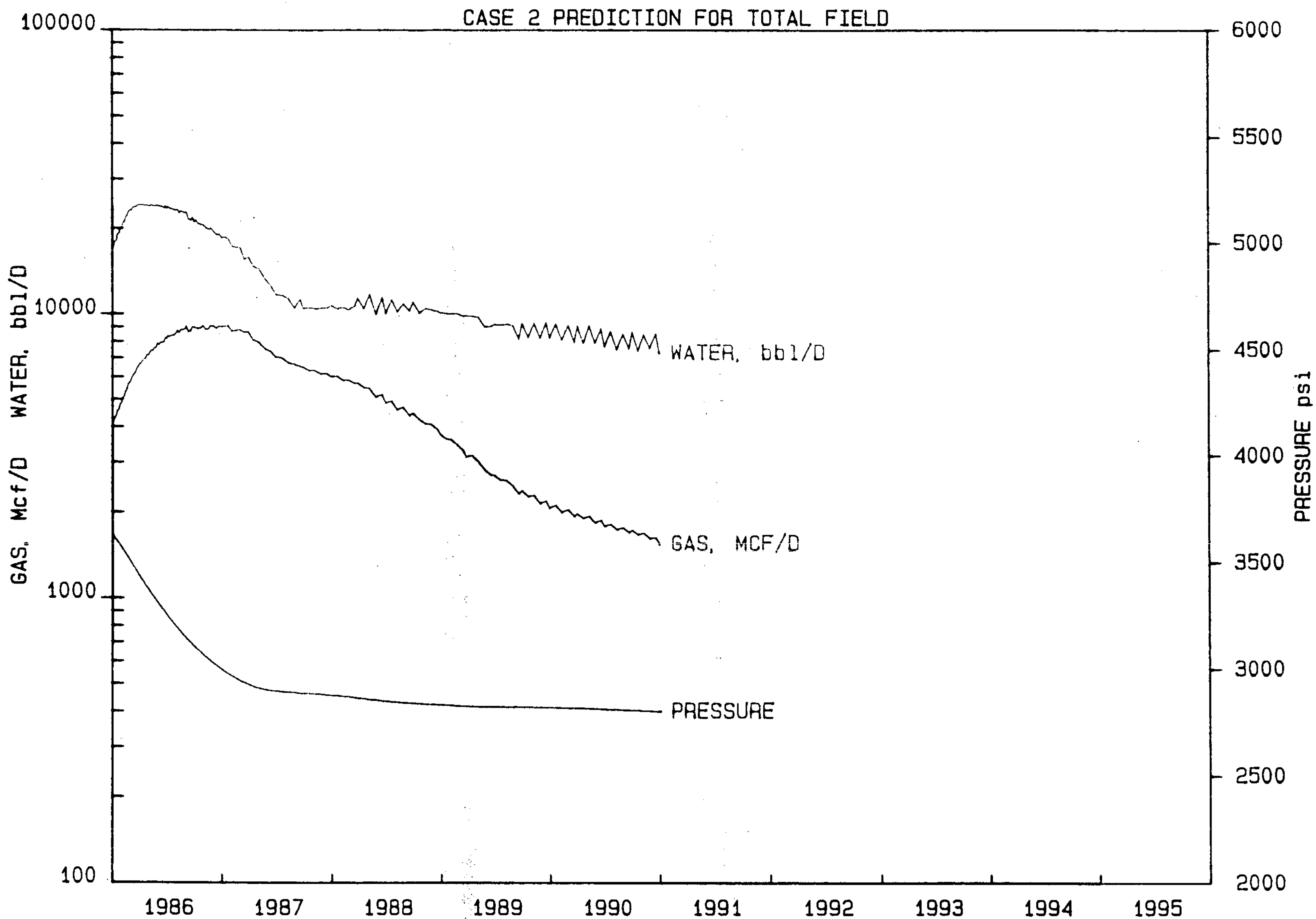
Well Name	Maximum Water bpd	CASE 1	CASE 2	CASE3
Huff A #1	2000		X	X
Prets #1	4300	X	X	X
Thompson #1	6000	X	X	X
Delee #1	6000		X	
Lemm #1	6000		X	



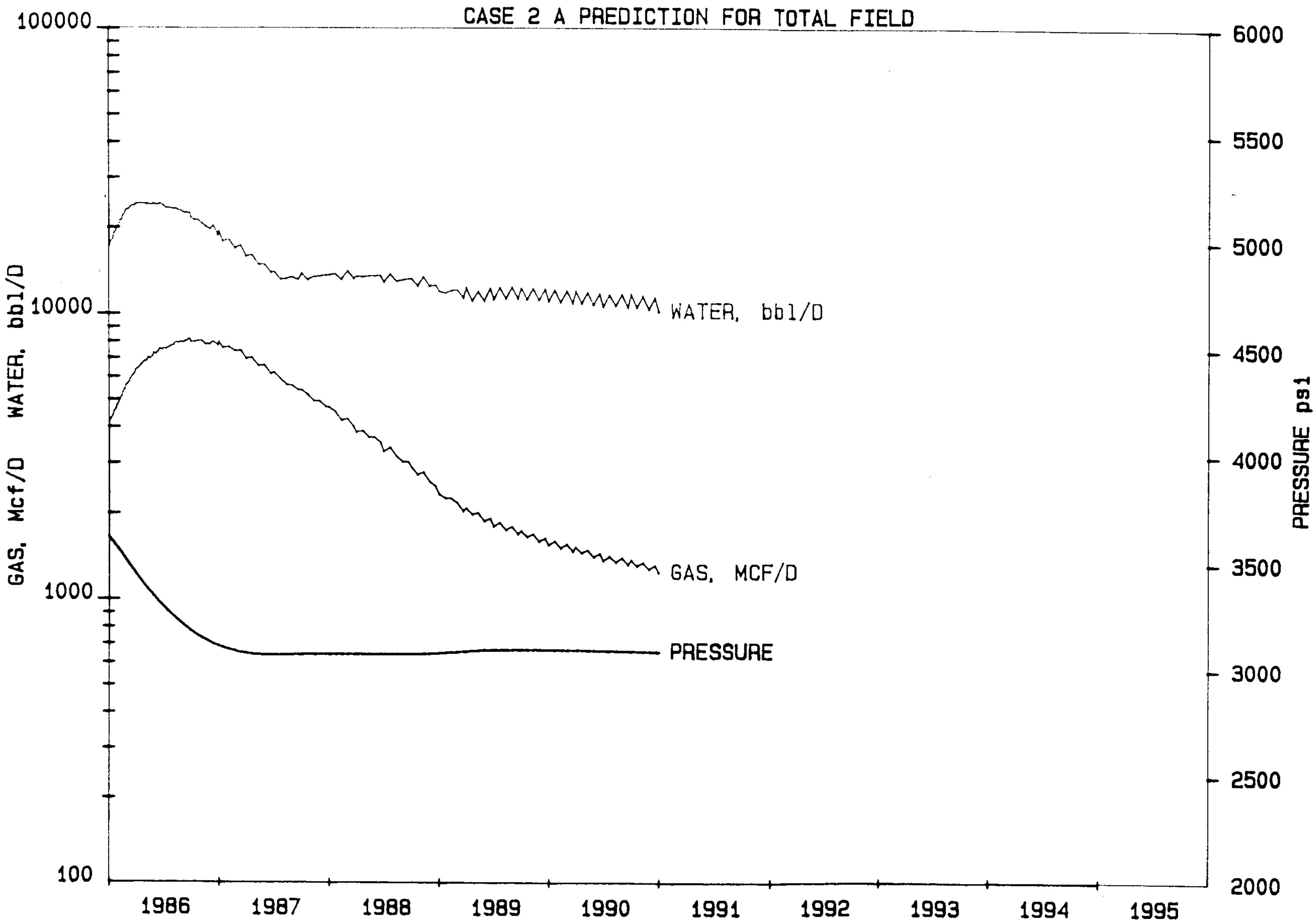
CASE 1 PREDICTION FOR TOTAL FIELD
100000
10000
1000
100
GAS, Mcf/D WATER, bbl/D
6000
5500
5000
4500
4000
3500
3000
2500
2000
PRESSURE psi
WATER, bbl/D
GAS, MCF/D
PRESSURE
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995

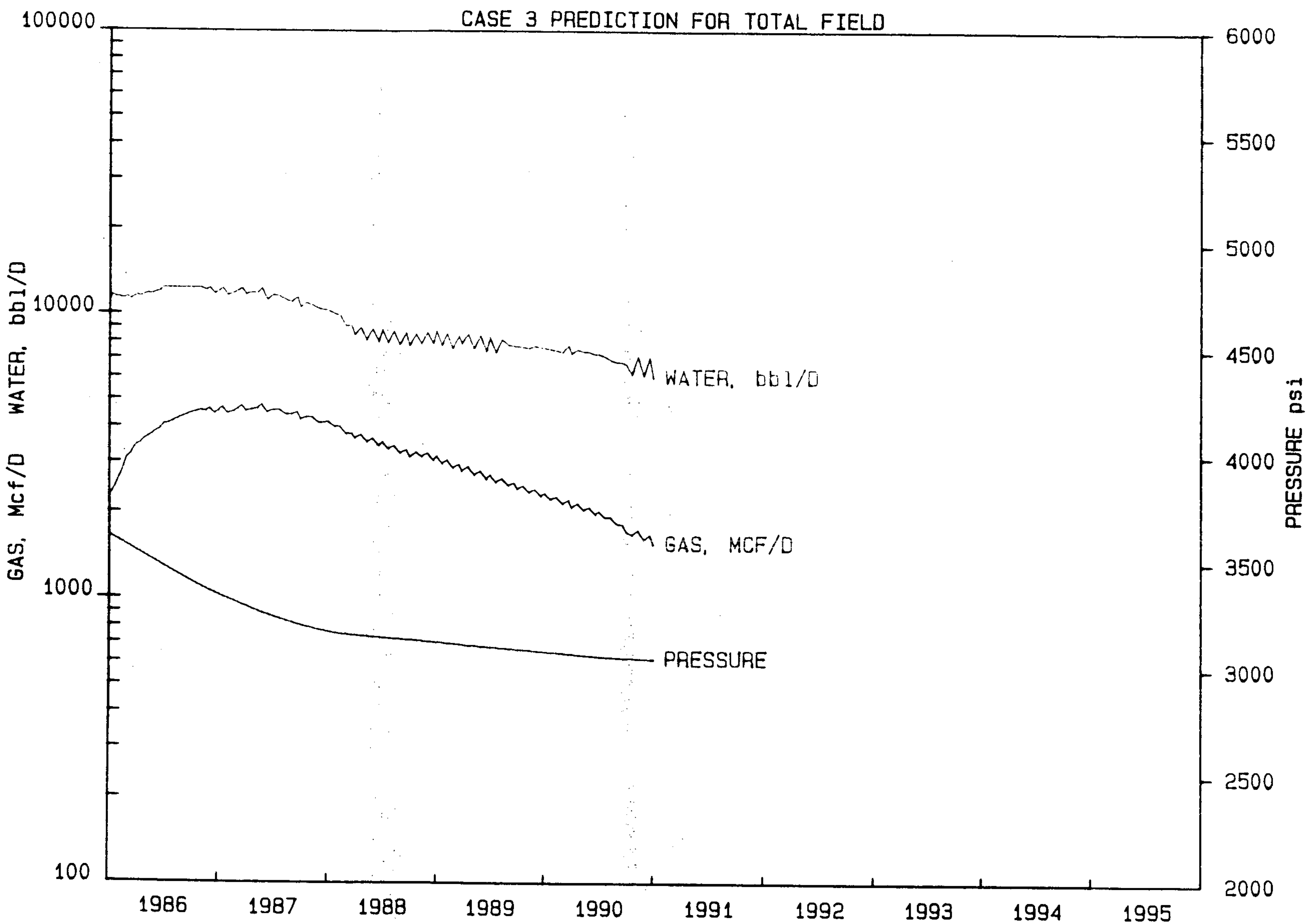


CASE 1A PREDICTION FOR TOTAL FIELD
100000
10000
1000
100
GAS, Mcf/D WATER, bbl/D
6000
5500
5000
4500
4000
3500
3000
2500
2000
PRESSURE psi
WATER, bbl/D
GAS, MCF/D
PRESSURE
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995



CASE 2 PREDICTION FOR TOTAL FIELD
100000
10000
1000
100
GAS, Mcf/D WATER, bbl/D
6000
5500
5000
4500
4000
3500
3000
2500
2000
PRESSURE psi
WATER, bbl/D
GAS, MCF/D
PRESSURE
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995


CASE 2 A PREDICTION FOR TOTAL FIELD
GAS, Mcf/D WATER, bbl/D
PRESSURE psi
100000
10000
1000
100
6000
5500
5000
4500
4000
3500
3000
2500
2000
WATER, bbl/D
GAS, MCF/D
PRESSURE
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995



CASE 3 PREDICTION FOR TOTAL FIELD
100000
10000
1000
100
GAS, Mcf/D WATER, bbl/D
6000
5500
5000
4500
4000
3500
3000
2500
2000
PRESSURE psi
WATER, bbl/D
GAS, MCF/D
PRESSURE
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995

T. APPENDIX 20

SUMMARY OF SCALE AND ADVERSE CHEMICAL REACTION RESEARCH

M. TOMSON/RICE UNIVERSITY

RICE UNIVERSITY

Houston, Texas

BRINE CHEMISTRY AND

CONTROL OF ADVERSE CHEMICAL REACTIONS

WITH NATURAL GAS PRODUCTION

PROJECT REVIEW

GAS RESEARCH INSTITUTE

22 APRIL 1986

Department of

Environmental Science and Engineering

Mason B. Tomson
Peggy O'Day
Janet L. Greenberg

Sethuraman Gopalakrishnan T.S.U.

Not presently working on project
Kuruvila Varughese
Jane Matty
Puthugramam C. Sundareswaran
Gordon Waggett

OUTLINE OF PRESENTATION

I. PROBLEM AND SOLUTION METHOD

II. SUMMARY OF PROGRESS PRIOR TO PRESENT REVIEW YEAR

III. WORK ACCOMPLISHED THIS YEAR

IV. PRESENT NEEDS AND APPROACHES TO SOLUTION

CONTRACT SCOPE

Chemical analysis of gas, liquid and solid phases produced from co-production wells. Develop ways to mitigate or control adverse chemical reaction, such as scale and corrosion. Conduct field tests, laboratory studies, and theoretical analyses to remove uncertainties about the technical problems of production, processing, and disposal of brine from co-production wells.

ORIGIN OF ADVERSE CHEMICAL REACTIONS

SCALE:

$$Ca^{2+} + HCO_3^- \xrightarrow{\nearrow CO_2} CaCO_3 + H^+$$

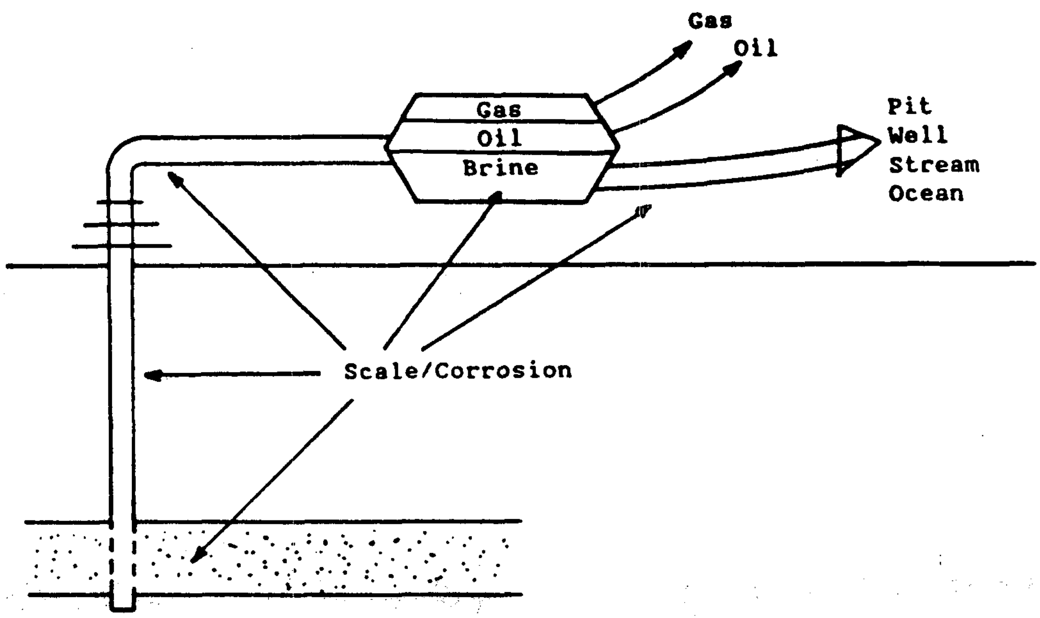
BRINE CALCIUM + BICARBONATE ALKALINITY → CALCITE SCALE + ACID

CORROSION:

$$Fe^{\circ} + \begin{matrix} 2H_2O \cdot CO_2 \\ 2H_2CO_3 \end{matrix} \longrightarrow Fe^{2+} + H_2 + 2HCO_3^-$$

IRON PIPE + CARBONIC ACID → DISSOLVFD PIPE + HYDROGEN + BICARBONATE ALKALINITY

Overview of Project



Objective: Predict, measure, and mitigate scale and corrosion. Information transfer.

Approach: Chemical measurements, laboratory simulations, and theoretical studies.

Conventional Wisdom		
	To Prevent	
Parameter	Scale	Corrosion
Temperature	↓	↓
Pressure	↑	↓
Dissolved Salts	↑	↓
pH	↓	↑
Saturation Index	↓	↑
Typical Inhibitors	Phosphonates Polyacrylates Polymaleates at 1 to 10 mg/l	Amines Thio-Amines Fatty Acids to 1000 mg/l Zinc Chromates 1 to 10 mg/l $CaCO_3$-Film

SATURATION INDEX

AND

BRINE CHEMISTRY KIT

SI Equations

$$SI = \log \left\{ \frac{(Ca)(CO_3)}{K_{sp}} \right\}$$

+ Supersaturated (~ 2.5 max.)
= 0 Saturated (± 0.3)
- Unsaturated--no problem

$$SI = \log \left\{ \frac{T_{Ca} Alk^2}{Px_{CO_2}} \right\} + 5.89 + 1.549.10^{-2}T - 4.26x10^{-6}T^2$$

$$- 7.44x10^{-5}P - 2.526I^{1/2} + 0.920I$$

ALSO:

$$pH = -\log \left\{ \frac{Px_{CO_2}}{Alk} \right\} + 8.68 + 4.05x10^{-3}T + 4.58x10^{-7}T^2$$

$$- 3.07x10^{-5}P - 0.477I^{1/2} + 0.193I$$

T_{CA} - MOLAR = PPM CA/40000

ALK - MOLAR = PPM HCO_3^-/61000

P - PSI

X_{CO_2} - MOLE FRACTION OR VOLUME FRACTION CO_2 IN GAS

T - °F

I - MOLAR IONIC STRENGTH ~1.5 X 10^{-5} CONDUCTANCE (μMHOS/CM)

~PPM TDS/56000

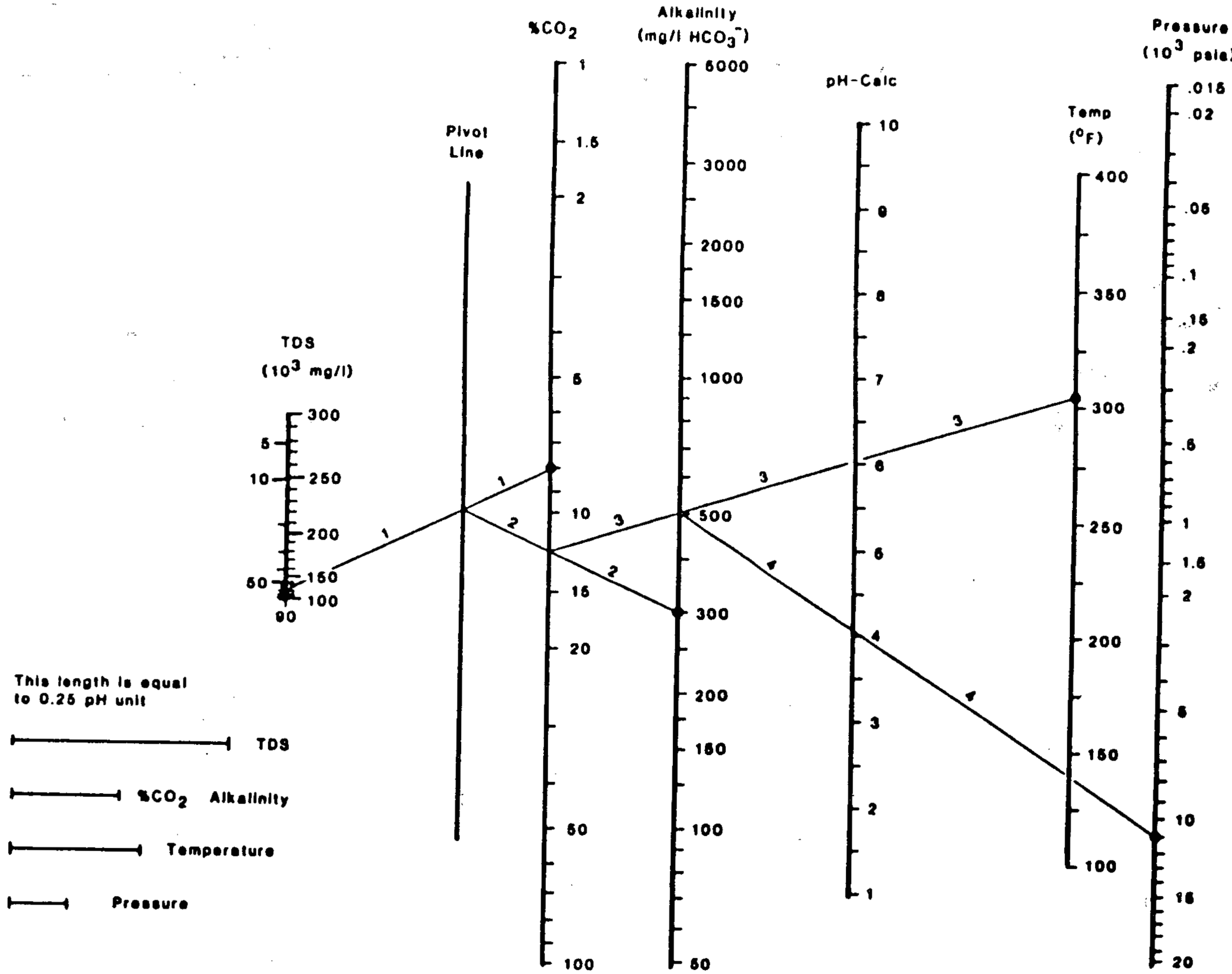


Figure 1. Nomograph for calculating brine pH. Lines numbered 1-4 depict a sample nomogram constructed as follows: Line 1 connects the TDS value to the $\%CO_2$ value; Line 2 connects the intersection of Line 1 and the pivot line with the alkalinity value; Line 3 connects the intersection of Line 2 and the $\%CO_2$ scale with the temperature value; Line 4 connects the intersection of Line 3 and the alkalinity scale with the pressure value. The answer (pH-calculated) is read as the intersection of Line 4 and the pH scale.

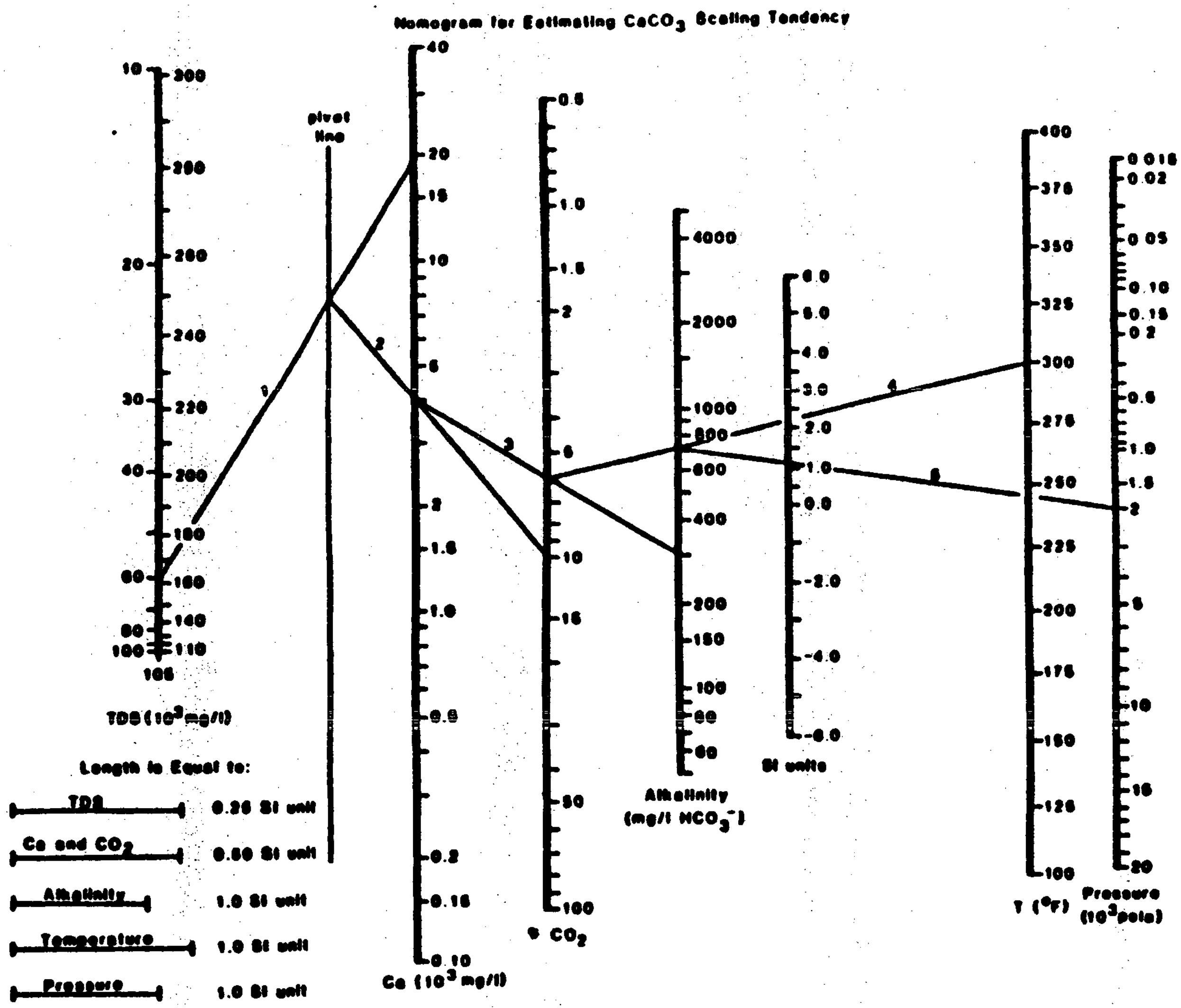


Figure 2. Nomograph for calculating CaCO₃ saturation index. Sample nomogram is constructed in the same manner described for Figure 3.1. The answer (Saturation Index value) is read as the intersection of Line 5 and the SI unit scale.

Change in Saturation Index

$$\Delta SI = SI_2 - SI_1$$
$$= \Delta SI_P + \Delta SI_T + \Delta SI_{Ca} + \Delta SI_{Alk} + \Delta SI_{CO_2} + \Delta SI_{TDS}$$

→ Eliminate systematic errors

→ Identify significant parameters

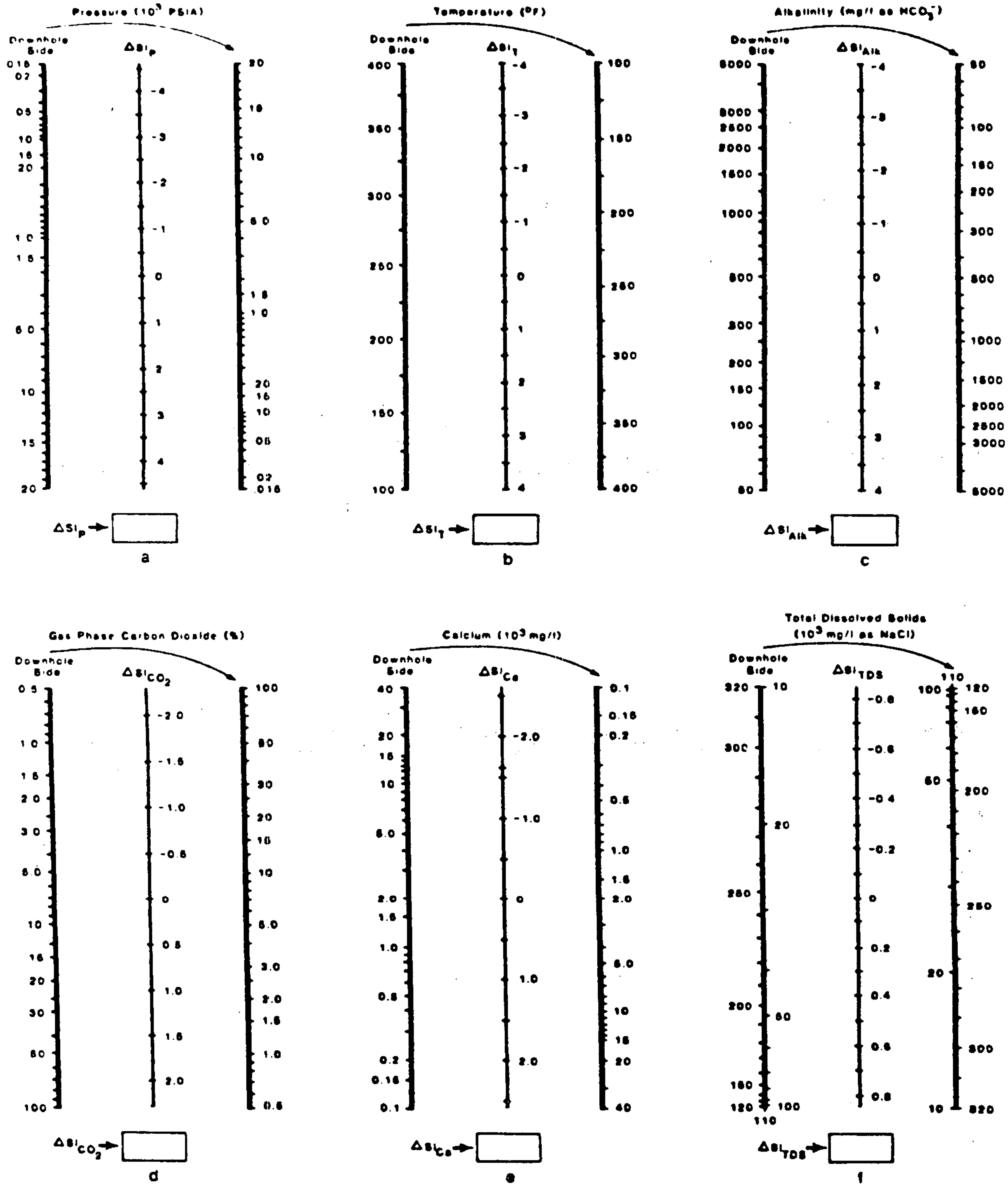


Figure 3. Nomograph for calculating ΔSI. The effect of each component is calculated separately by connecting the value for the downhole side to the value of the upstream side and reading the component of ΔSI as the intersection of that line with the ΔSI scale between them. The total ΔSI is the sum of the ΔSI of all the components. Component nomographs for calculating the change in saturation index due to change in:

a) Pressure (ΔSI_P)
b) Temperature (ΔSI_T)
c) Alkalinity (ΔSI_{Alk})
d) $\%CO_2$ (ΔSI_{CO_2})
e) Calcium ion (ΔSI_{Ca})
f) Total dissolved solids (ΔSI_{TDS})

Table 4. Summary of Production Data and ΔSI Values During Long Term Tests at Gladys McCall No. 1 Well Performed to Establish a Correlation Between Brine Production Rate and Scale Formation.

Study Period	No. Days in Study Period	Avg. Prod. (B/D)	Range of Surface Pressure (PSIA)	Avg. Meas. Chg. in Surface Pressure (ΔPSI/D)	Avg. Reservior Decline (ΔPSI/D)	Avg. Chg. in Surf. Pressure due to scale Formation (ΔPSI/D)	Range of ΔSI at Surface
June, July 1984	32	20,219	3549-2743	15.3	7.8(7.8)*	7.5	1.30-1.25
July, Aug 1984	34	15,411	4238-4124	4.4	5.8(5.8)	0	1.10-1.12
Aug, Sept 1984	19	24,574	2718-2200	31.9	8.7(9.6)	23.2	1.50-1.30

*The values in paranthesis were calculated using a reservoir simulation model (Durrett, 1984).

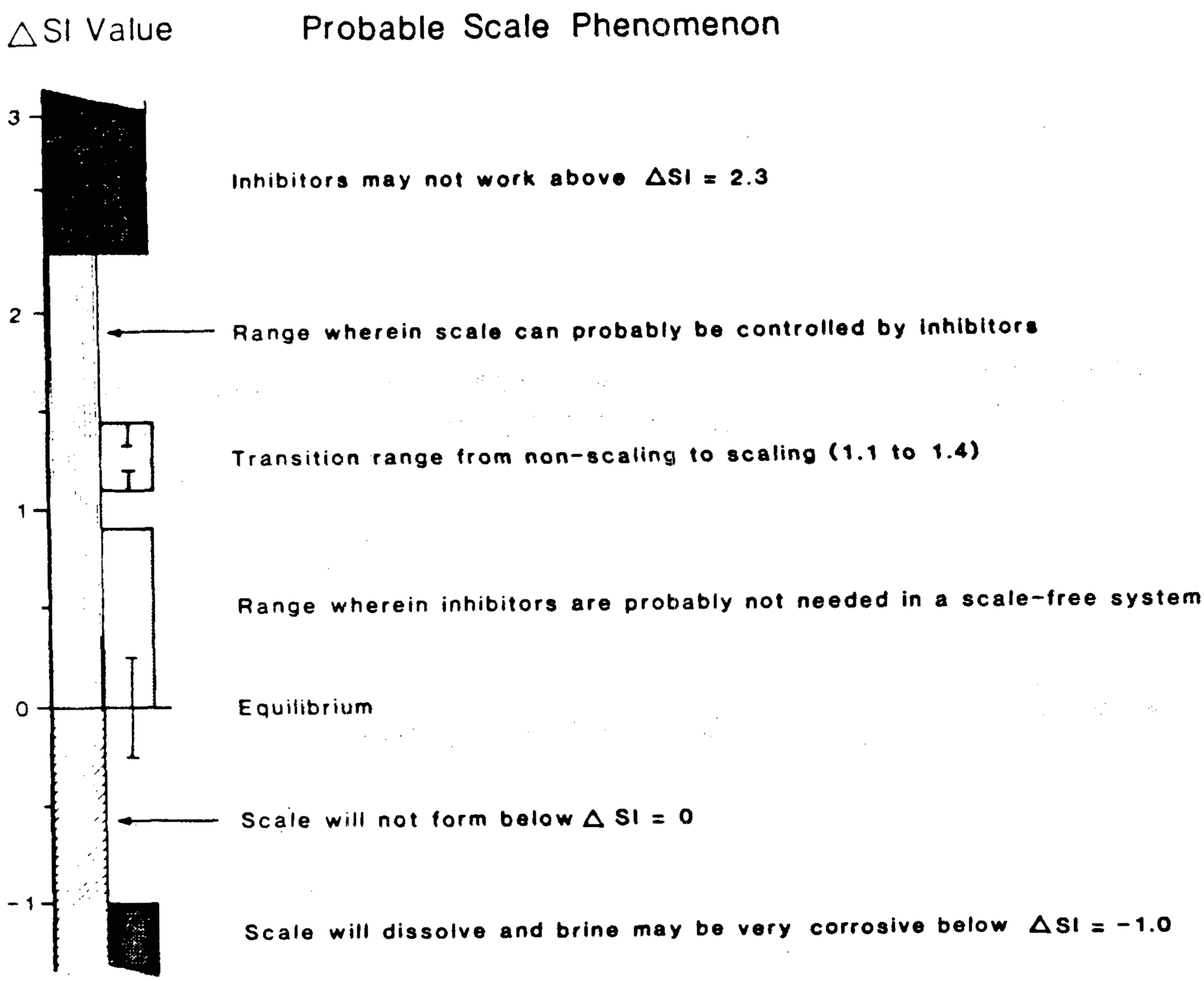


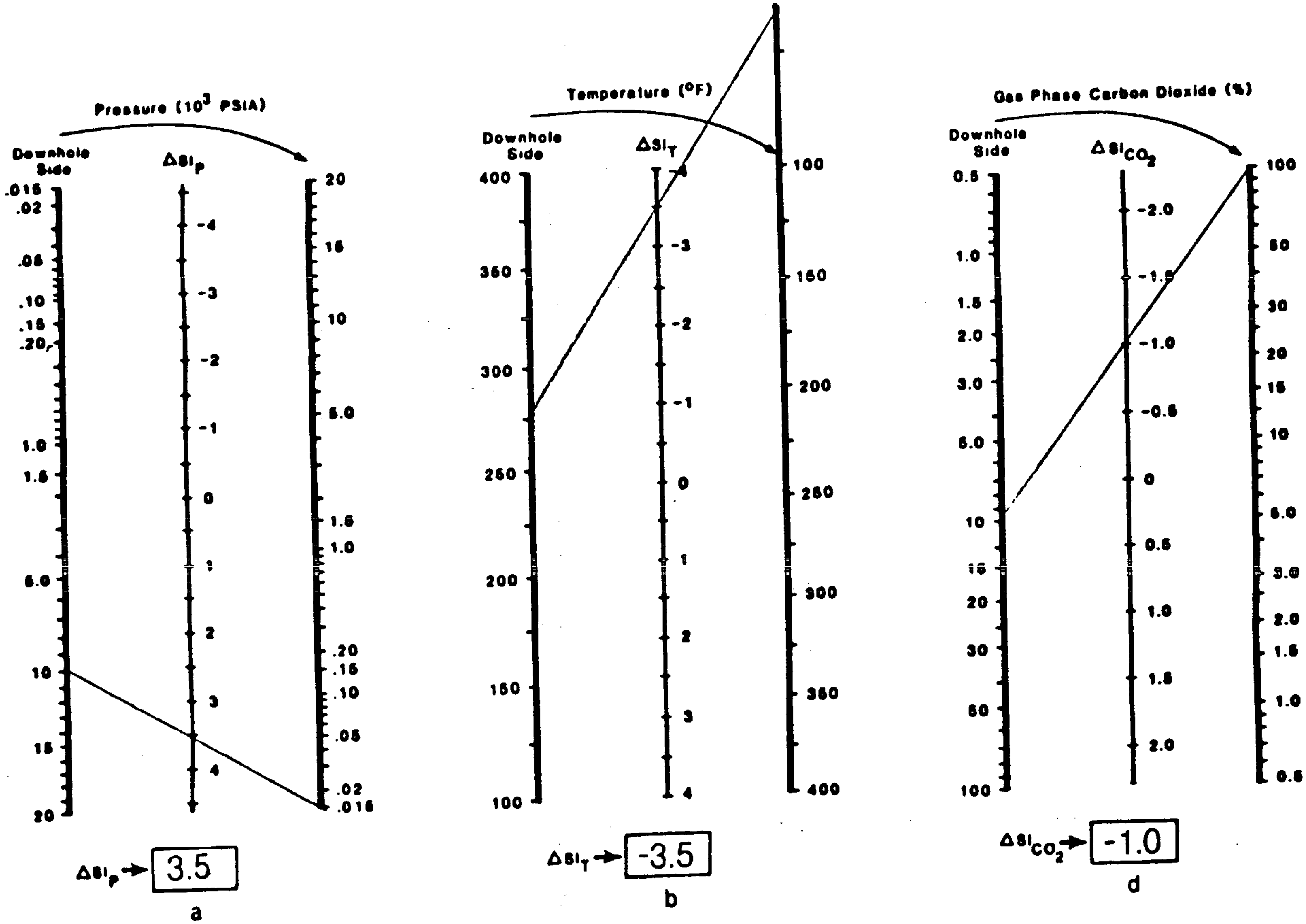
Figure 4. Depiction of ΔSI values and corresponding scale-related phenomena for $CaCO_3$ scale-forming brines. The ΔSI values are relative to downhole shut-in conditions wherein it is assumed that the brine is at equilibrium with respect to calcium carbonate.

Difficulties in monitoring brine chemistry

1.Sample will precipitate under normal conditions

2.Absence of a simple brine chemistry monitoring technique for field operator

Nomograph used for calculating saturation index



+3.5-3.5-1 = -1.0

$\Delta SI = -1.0$

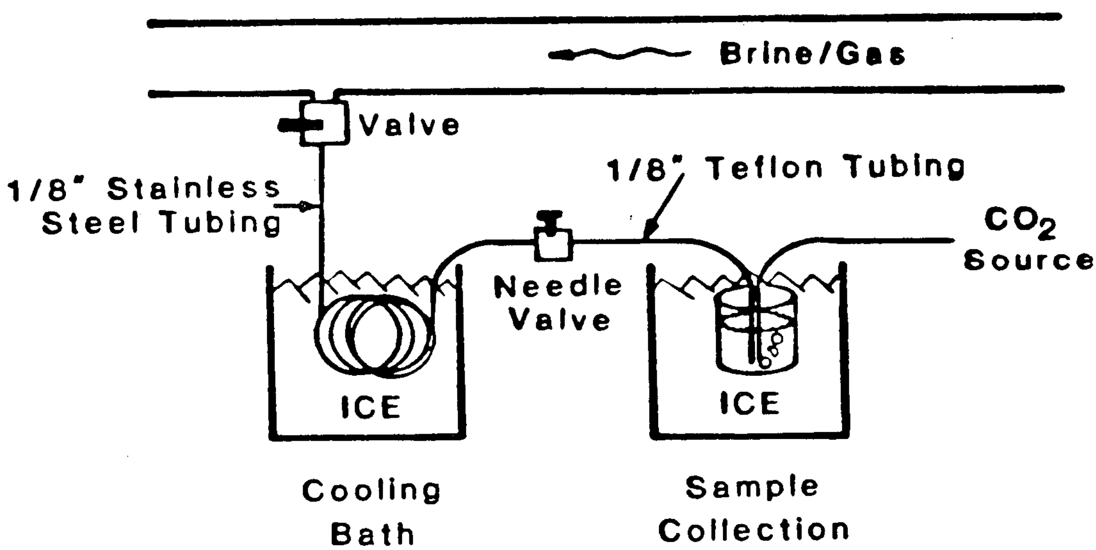


Figure 5. Diagram of setup used for sample collection. 1/8-inch stainless steel tubing is attached to the main stem at a valve. A coil is placed into an ice bath; the length should be at least 40 feet to ensure sufficient cooling of the brine. The stainless steel tubing terminates at a needle valve used to control the flow rate. The brine then flows through Teflon tubing into a collection bottle which is also in an ice bath. CO_2 is bubbled into the sample as it is collected (see text).

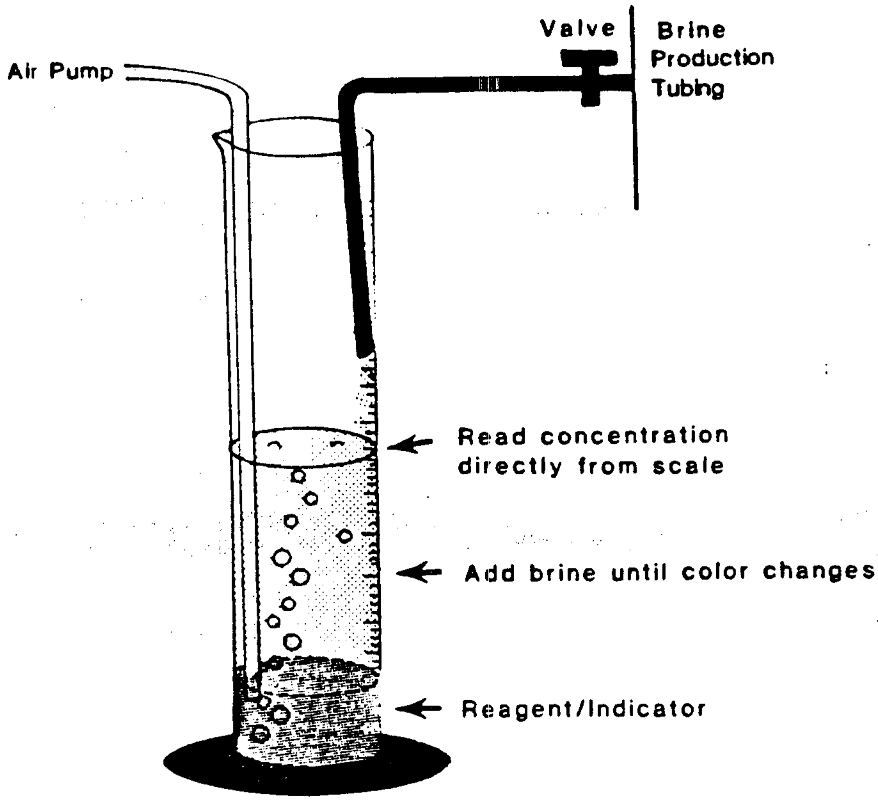


Figure 6. Diagram of field brine analysis kit. Pre-measured reagent is added to a graduated cylinder which is marked with the appropriate concentration scale. Brine is added, using a gas source (such as an aquarium air pump) to mix the solution, until the color changes. The concentration is read as the level of liquid in the cylinder.

CONCENTRATION AND MEASUREMENT RANGES OF THE KIT

Kit	Reagents	Measurement Range mg/l	Measurement Range Mol	Observed Conc. of Brine in the Geopressured Wells Mol
Alkalinity - 1	0.02 m HNO_3 + Bromophenol blue Indicator	120 - 1200	0.002 - 0.02	0.004 - 0.06
Alkalinity - 2	0.15 m HNO_3 + Bromophenol blue Indicator	900 - 9000	0.015 - 0.15	
Calcium - 1	0.016 Media + Calver II Indicator	30 - 320	0.0008 - 0.008	0.001 - 0.30
Calcium - 2	0.10 Media + Calver II Indicator	250 - 2600	0.0065 - 0.065	
Calcium - 3	1.0 Media + Calver II Indicator	2000 - 20,000	0.0500 - 0.50	
Chloride*	0.5 m $Hg(NO_3)_2$ + Diphenyl carbazone and Bromophenol blue Indicators	15,000 - 142,000	0.3000 - 4.0	0.50 - 4.0

*Chloride can be measured accurately using a conductivity meter.

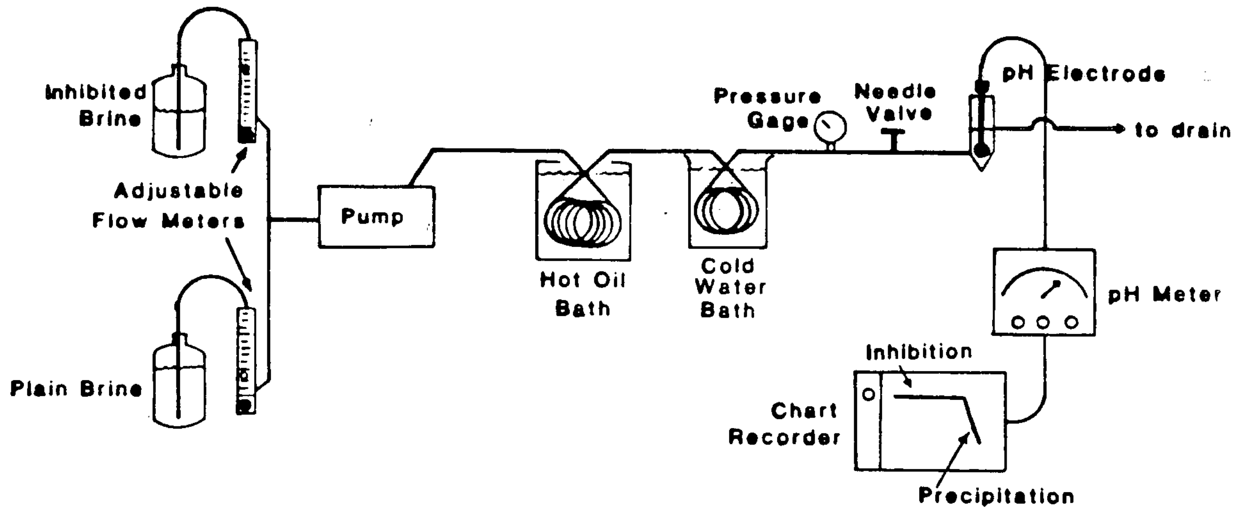
INHIBITORS

Theory of $CaCO_3$ Inhibition

Laboratory Evaluation

General Theory of Scale Inhibition

Future Plans



$CaCO_3$ - WIDER RANGE OF CONCENTRATIONS AND pHs. RESULTS WERE IN AGREEMENT WITH THEORY:

$$\sum z\ (In^{z-}) > 2\ CO_3^{2-}$$

$CaCO_3$ - EFFECT OF Mg^{2+}, Sr^{2+}, Ba^{2+}, and SO_4^{2-} ON INHIBITORS. Sr^{2+} HAD NO EFFECT. Ba^{2+} RESULTS WERE MINIMAL AND MIXED. Mg^{2+} AND SO_4^{2-} INHIBITED $CaCO_3$ AT 0.094 M AND 0.020 M, RESPECTIVELY AND TOGETHER ARE ADDITIVE. IN CONJUNCTION WITH PHOSPHONATES BOTH Mg^{2+} AND SO_4^{2-} ARE GENERALLY ADDITIVE.

$CaSO_4$ - A CORRESPONDING FLOW-THROUGH APPARATUS FOR $CaSO_4$ INHIBITION STUDIES HAS BEEN DEVELOPED. SEVERAL INHIBITORS HAVE BEEN STUDIED; ALL INHIBITED PRECIPITATION OF $CaSO_4$ AT LESS THAN 1 mg/l.

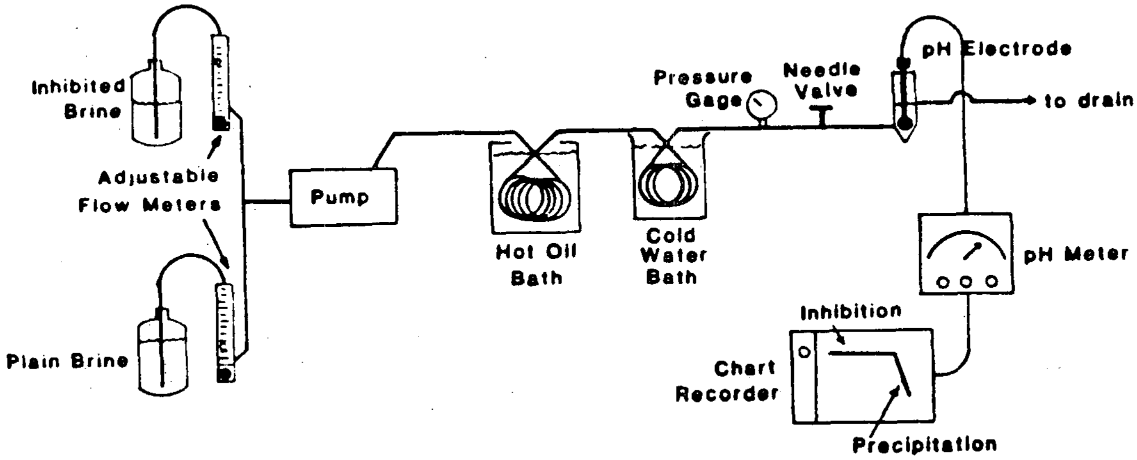


Figure 7. Diagram of inhibitor evaluation apparatus. All tubing and fittings are of Teflon or Kel-F ("Instac", available from Cole-Parmer). In general, two solutions are used: an inhibited and an untreated brine. Proportions of the two feed solutions are adjusted by flowmeters (Cole-Parmer variable area flowmeter model R-3216-14). The resulting solution is pumped (Eldex model BBB-4 triple piston pump with Kel-F lined valves and pump heads) into the reaction coil (~40 ft. of tubing) which is situated in a Messgerate-Werk Lauda UltraThermostat constant temperature bath filled with Dow-Corning Silicone 200 oil maintained at 125C (257F). The flow rate is adjusted so that residence time in the oil bath at temperature is > 1 minute (for 40 ft. coil, flow rate is ~5 ml/min). The brine then passes into a water bath maintained at room temperature, past a pressure gauge, to a metering valve (Nupro model SS-2SG) which controls backpressure (generally 500 psi), and over the tip of a pH electrode (Orion-Ross epoxy body combination electrode) and into a drain. The pH is read by a pH meter and recorded on a strip-chart recorder. Precipitation is noted as a drop in pH due to the reaction $HCO_3^- + Ca^{2+} \rightarrow CaCO_3 + H^+$. Inhibition results in a stable pH.

Class	Name	Minimum [Inh] Old	(ppm) New	$\frac{\Sigma[CO_3]}{\Sigma[Inh]}$
Phosphonates	Dequest 2000 – ATMP	0.10	0.10	0.44
	Dequest 2010 – HEDP	0.20	0.09	0.67
	Dequest 2060	0.20	0.09	0.69
	WTC–01	0.50	0.50	0.08
	WTC–03	0.50	0.08	0.51
	WTC–04	0.10	0.08	0.56
	WTC–05	0.05	0.05	0.97
	WTC–06	0.05	0.08	0.63
	WTC–10	0.10	0.05	0.96
	WTC–11	0.20	0.25	0.25
Phosphate Ester	PE–22	0.25	0.16	0.72
Mixed Phosphonate and Carboxylate	WTC–08	0.055	0.16	0.72
Polyacrylates	P–42	0.60	0.40	0.06
	OFC–1255	n.d.	0.70	0.18
Polymaleic Anhydride	Belclene 200	0.60	0.14	0.76
Citric Acid		20.00	20.00	0.002
Sodium Hexamethaphosphate		1.0	1.0	0.15
Phosphate		1.0	2.0	0.02

Laboratory Results

Inhibitor	$\frac{Z(CO3)}{Z(Inh)}$
AMP-20	0.35
Dequest 2000	0.44
Dequest 2010	0.67
Dequest 2060	0.69
WTC-08	0.63
WTC-11	0.25
PE-22	0.72
P-42	0.06
ARCO Polyacrylate	0.15
OFC-1255	0.18
Belclene 200	0.76
Belclene 260	0.04
Gyptron T96	0.06
Phosphate	0.02
Citric Acid	0.002

Field Results

WELL	
Gladys McCall No. 1	~~0.07~~ 0.30
Pleasant Bayou No. 2	0.08
AMOCO Fee No. 1 (Sweet Lake)	0.03
Crown Zellerbach No. 2	0.03
Prairie Canal No. 1	0.39

Multiple Inhibitors

Inhibitor theory suggests additive behavior

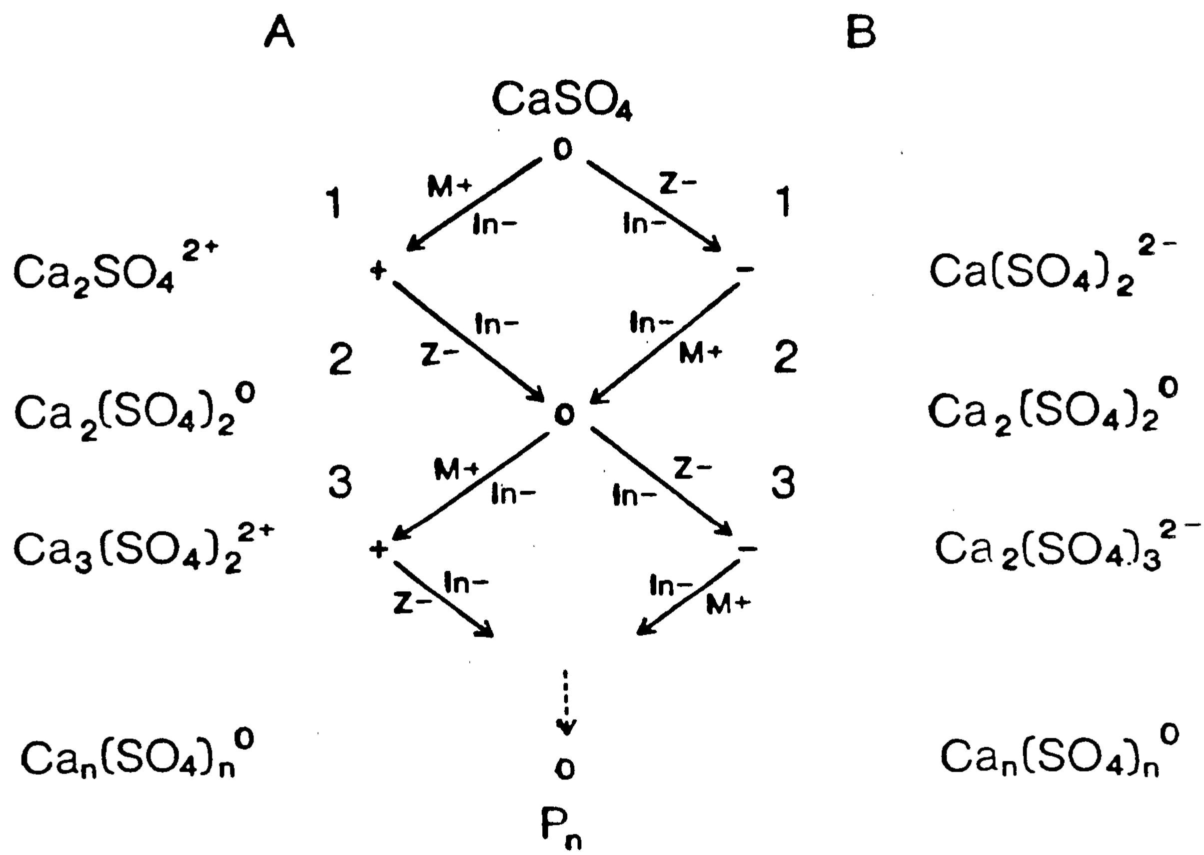
$$\frac{2(CO_3)}{\sum_i Z_i(Inh_i)} < 1$$

Might be possible to extend upper limit of inhibitor usefulness

Evaluation of Inhibitor Mixtures

Mixture	Minimum % Each for Inhibition	$\frac{\Sigma[CO_3]}{\Sigma[Inh]}$
A. 2-Inhibitor Mixtures (expect 50% each)		
1. Dequest 2000 + PE-22	50	0.55
2. Dequest 2000 + Belclene 200	50	0.56
3. Dequest 2000 + WTC-11	50	0.32
4. Dequest 2000 + WTC-08	50	0.52
5. PE-22 + Belclene 200	50	0.74
6. PE-22 + WTC-11	50	0.37
7. PE-22 + WTC-08	40	0.67
8. Belclene 200 + WTC-11	50	0.38
9. Belclene 200 + WTC-08	50	0.69
10. WTC-11 + WTC-08	50	0.36
B. 3-Inhibitor Mixtures (expect 33% each)		
1. Dequest 2000 + PE-22 + Belclene 200	33	0.61
2. Dequest 2000 + Belclene 200 + WTC-08	33	0.58
3. Dequest 2000 + Dequest 2010 + Dequest 2060	33	0.57
C. 5-Inhibitor Mixture (expect 20% each)		
1. Dequest 2000 + PE-22 + Belclene 200 + WTC-11 + WTC-08	17	0.57

Schematic Model



$$P_A = \frac{(M+)}{(M+) + (Z-)} \qquad P_B = \frac{(Z-)}{(M+) + (Z-)}$$

$$P_{A1} = \frac{(M+)}{(M+) + (In-)} \qquad P_{B1} = \frac{(Z-)}{(Z-) + (In-)}$$

$$P_{A2} = \frac{k_{\pm}(Z-)}{k_{\pm}(Z-) + k'_{\pm}(In-)} \qquad P_{B2} = \frac{k_{\pm}(M+)}{k_{\pm}(M+) + k_{\pm}(In-)}$$

Calcium Sulfate Inhibition

Inhibitor	pH	Minimum Conc. for Inhibitor (ppm)
Degrest 2000	6.0	0.3
Degrest 2060	6.0	0.2
	4.0	0.2
P-42 Polyacrylate	6.5	0.7
	4.0	1.4
ARCO Polyacrylate	6.5	0.3
Belclene 200 (PMA)	6.5	0.25
	4.0	0.50

FIELD WORK

SUMMARY OF SCALE AND CORROSION CONTROL

GLADYS McCALL #1 DESIGN WELL

I. Problem - $CaCO_3$ Scale Forming Downhole

A. Initial Action:

a. Removal of Scale with 15% HCL acid

b. Lower Production Rate

c. Evaluation of Downhole Inhibitor Application Techniques

II. Problem - $CaCO_3$ Scale Forming in Surface Equipment

A. Initial Action:

a. Surface Injection of Inhibitor

b. Very Low Tolerance in Inhibitor Concentration (i.e. <0.5 ppm -- $CaCO_3$ Scale; ~>1.0 ppm -- pseudoscale

III. Problem - Corrosion in Surface Equipment

A. Initial Action:

a. Replacement of Equipment as Needed

b. Evaluation and Cost Analysis for Surface Application of Inhibitors

T-F&S/DOE GLADYS McCALL NO. 1
CRAB LAKE FIELD - CAMERON PARISH, LOUISIANA
COMPLETION AUGUST 15, 1983

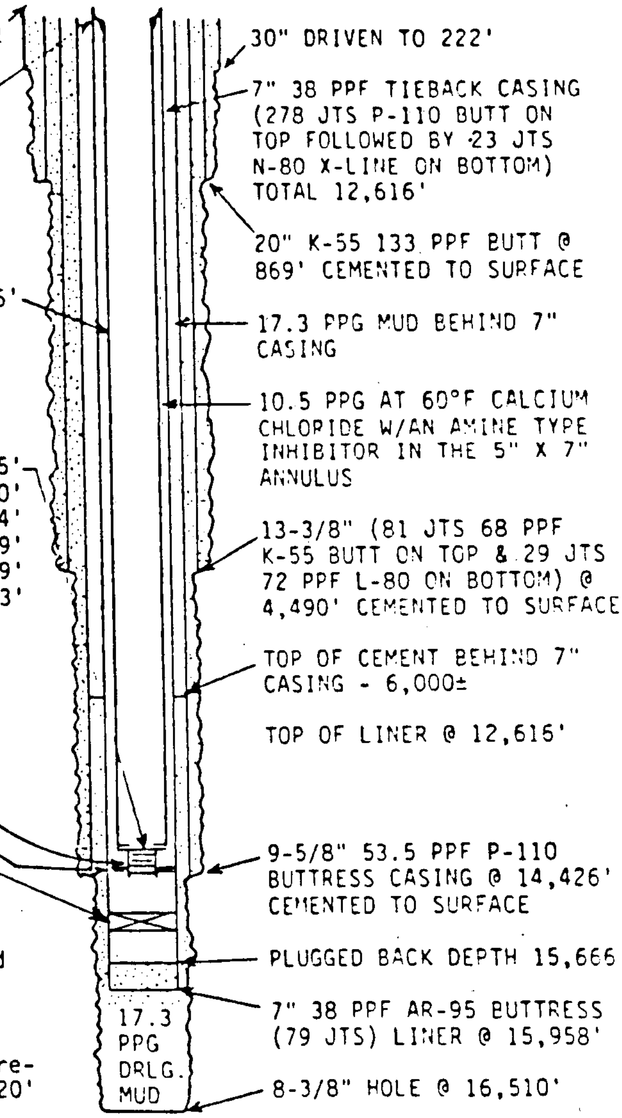
Material Description	Length	Setting Depth
*Rotary Table Elevation	21.20'	21.20'
Gray Tool tubing hanger, 5" modified VAM box connection on bottom and 5½" 8 rd thread box connection on top for 5½" 8 rd lift joint	1.31'	22.51'
372 joints 5" 18 ppf P-110 modified VAM connectors with special clearance Q-125 couplings	13,855.84'	13,878.35'
Otis Packer Seal Assembly		
Locator Sub	2.00'	13,880.35'
Seal Extension	9.75'	13,890.10'
Seal Mandrel	2.14'	13,892.24'
Seal Extension	7.85'	13,900.09'
Seal Mandrel	2.10'	13,902.19'
Mule Shoe	0.84'	13,903.03'

Seal Bore Extension (PBR)
Top 13,892.35'; Bottom 13,917.18'

Ratch Latch 13,917.18' to 13,920.00'

Otis WBR Packer 13,920.00' to 13,926.25'

Otis 7" 38# permanent WB Packer w/EP plug, 3.25" ID, set at 15,500' to 15,502.82' wireline measurement



NOTE: Locator sub set down on the PBR and picked up and spaced out 12' above the PBR to allow for tubing expansion.

*All tubing and associated equipment measurements are from rotary table elevation 21.20' above the 5" tubing hanger.

5" tubing lengths are as run (engineer's tally). Joints fall between API range 2 and range 3 averaging -37.25' in made up length.

SAND "9" perforated 4-shots per foot: 15,627'-15,567' and 15,541'-15,511'

DIAMETERS	ID	OD
Tubing Hanger	4.276"	8-5/8"
5" 18# Tubing	4.276"	5"
Tubing Couplings	4.276"	5.40"
Otis Seal Assembly	3.480"	4.46"
7" 38# Casing	5.920"	7"
Otis WB Packer	3.250"	5.44"

FIELD KIT RESULTS- GLADYS McCALL NO. 1

Date	Calcium (ppm)	Alkalinity (ppm)	Chloride (ppm)
3/06/85	4450	485	52,000
3/14/85	4500	500	50,000
3/15/85	4500	500	50,000
3/18/85	4500	500	50,000
3/19/85	4750	500	50,000
3/20/85	4600	480	48,000
3/21/85	4500	450	48,000
3/25/85	4500	430	50,000

Table 3. Brine Chemistry of the Gladys McCall Design Well

Parameter	2 Dec.1982
Temperature Leaving Separator (°F)	264
Disposal Pressure (psi)	250
Flow Rate (B/D)	9,000
Alkalinity (mg/l as HCO_3^-)	547
Calcium (mg/l Ca^{2+})	4,130
Chloride (mg/l Cl^-)	57,900
Conductivity (μmhos/cm)	126,360 @ 25°C
TDS (mg/l)	96,340
Hardness (mg/l as $CaCO_3$)	12,000
Iron (mg/l)	35
Silica (mg/l SiO_2)	135
Specific Gravity (g/cm^3)	1.062 @ 25°C
Sulfate (mg/l)	ND, < 5 ppm
Sulfide (mg/l)	ND, < 1 ppm
Scale Inhibitor Added (mg/l ATMP)	1.2
CO_2-Gas (Volume %)	7.6
S.I. at Disposal Well	2.55*

*Well will scale heavily if inhibitor is not added, particularly at higher temperatures.

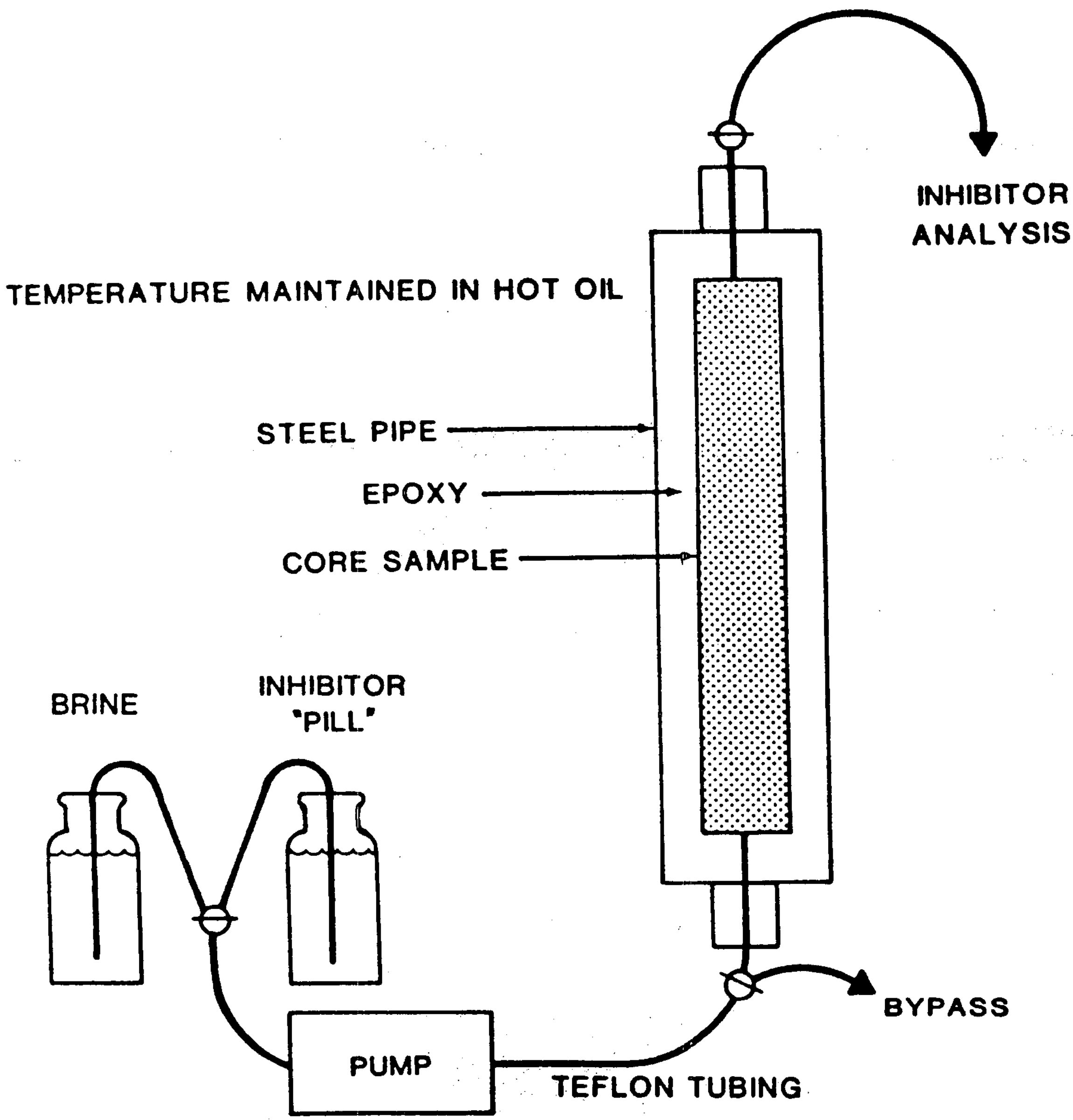


Figure 8. Schematic Diagram: Laboratory system used for simulation of downhole inhibitor application techniques.

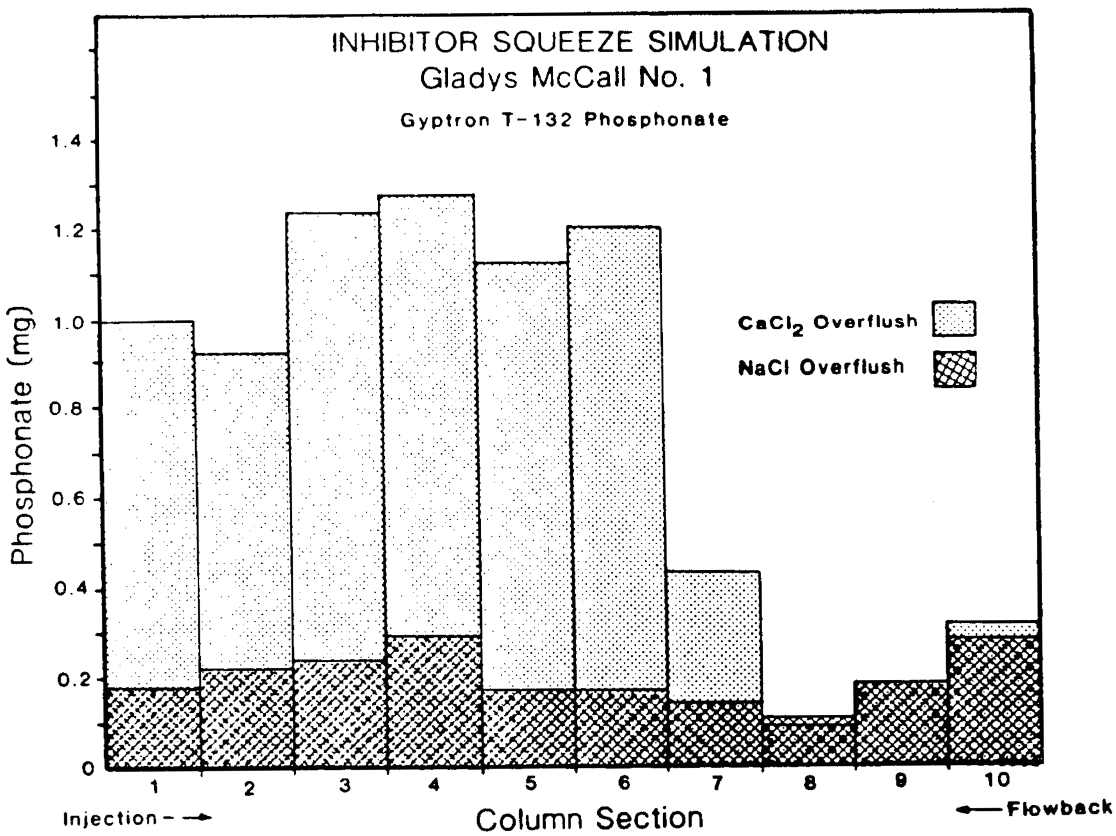
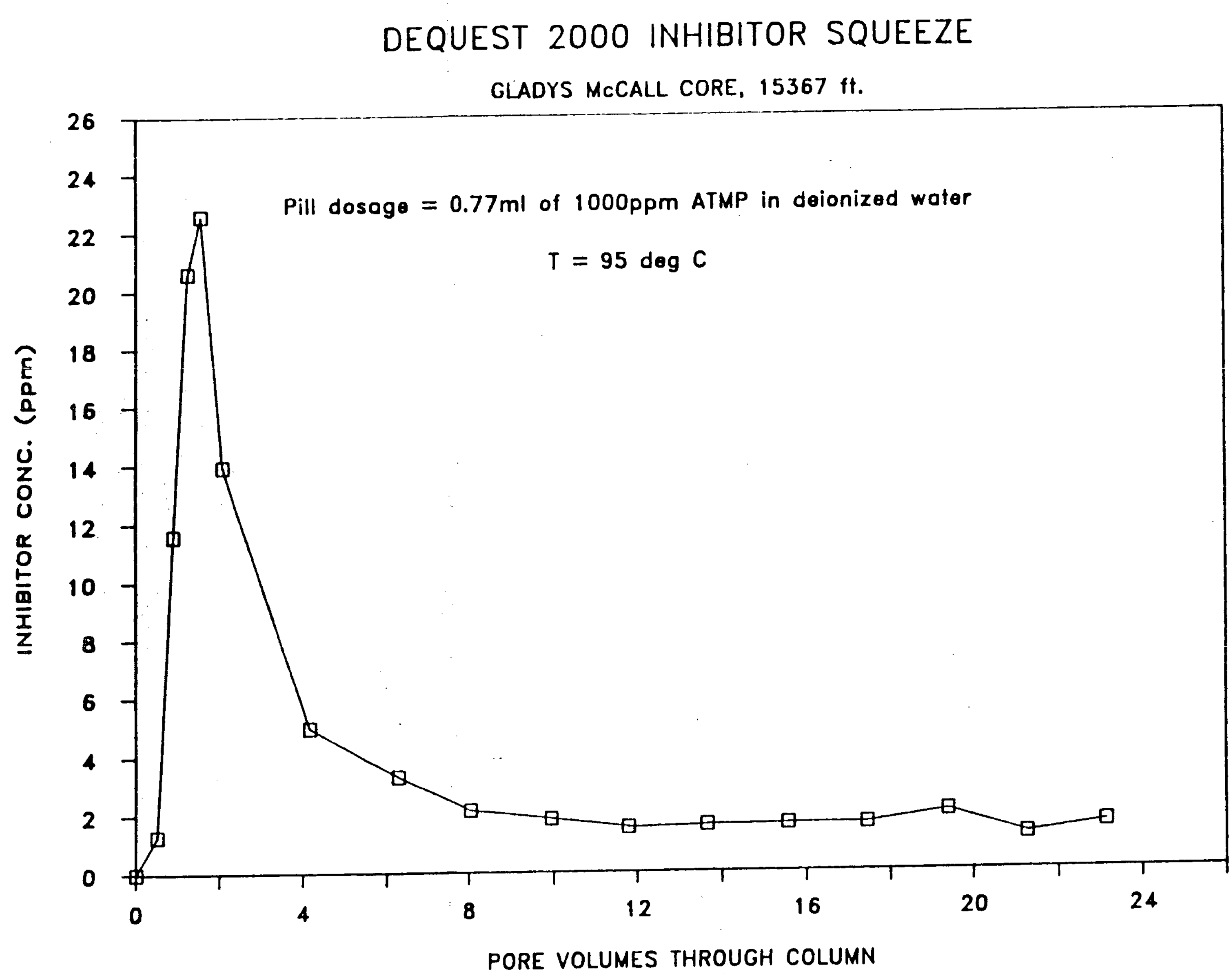
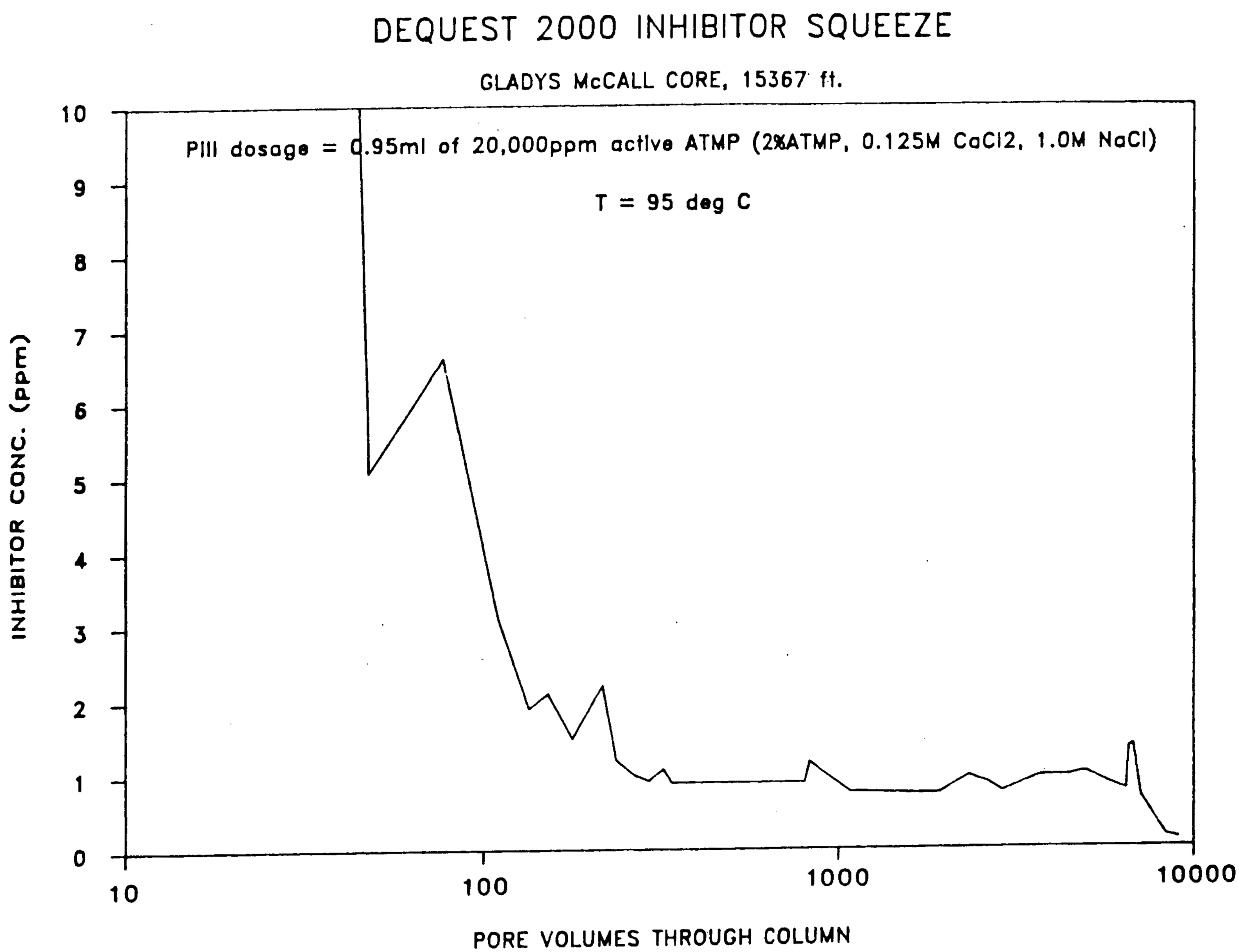


Figure 9. Results of laboratory squeeze simulation using core samples from the Gladys McCall No. 1 well. This represents amount of inhibitor remaining in the rock following injection and a short flowback, as a function of depth in the column. The increased effectiveness of the proposed pill with a calcium chloride overflush is significant.



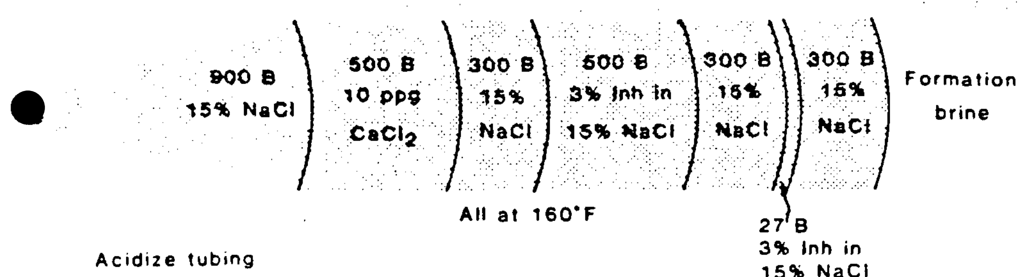
DEQUEST 2000 INHIBITOR SQUEEZE
GLADYS McCALL CORE, 15367 ft.
Pill dosage = 0.77ml of 1000ppm ATMP in deionized water
T = 95 deg C
INHIBITOR CONC. (ppm)
PORE VOLUMES THROUGH COLUMN
0
2
4
6
8
10
12
14
16
18
20
22
24
26
0
4
8
12
16
20
24



DEQUEST 2000 INHIBITOR SQUEEZE
GLADYS McCALL CORE, 15367 ft.
PIII dosage = 0.95ml of 20,000ppm active ATMP (2%ATMP, 0.125M CaCl2, 1.0M NaCl)
T = 95 deg C
INHIBITOR CONC. (ppm)
0
1
2
3
4
5
6
7
8
9
10
10
100
1000
10000
PORE VOLUMES THROUGH COLUMN

INHIBITOR SQUEEZE REGIME
GLADYS McCALL No. 1

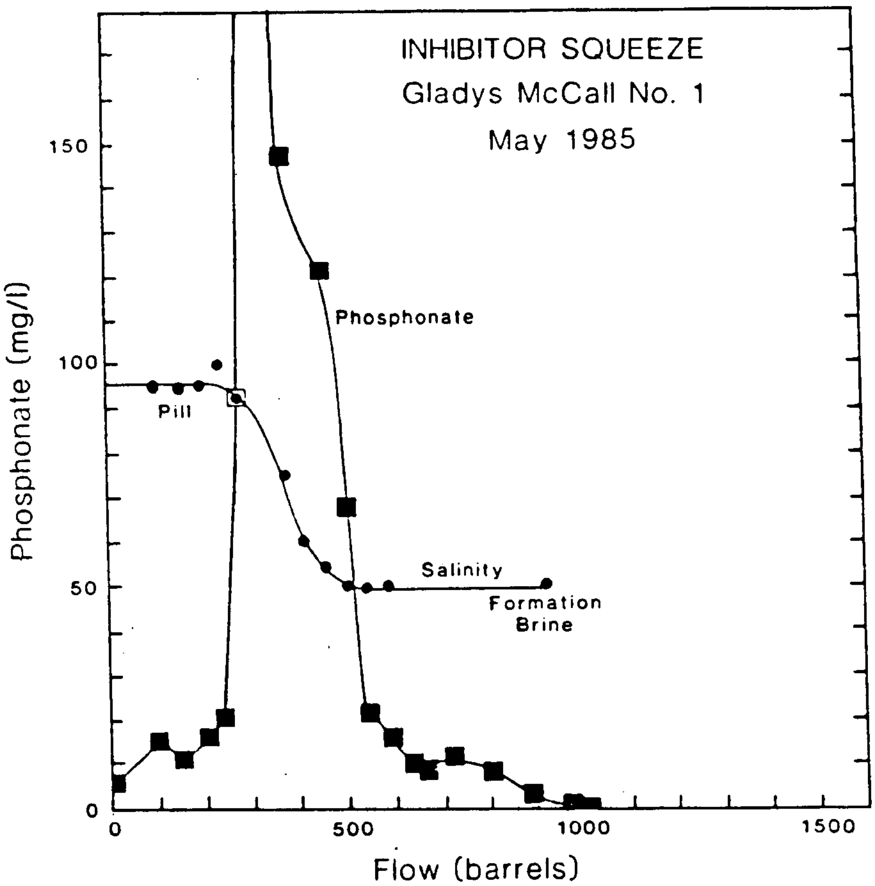
1. Plan



Acidize tubing
Inject - 2 BPM
Shut in 24 hrs.
Flow - 4000 BPD - 2 days
Flow - 25,000 BPD

2. Results

1. Found 400 ppm Ca & 8 ppm Fe in brine
2. 300 B NaCl injected, little resistance
3. 27 B pill injected, produced large resistance to pumping
4. Flow - 12,000 BPD for 8 hrs.
5. 6% pill tried, turbid : discarded
6. Another 25 B 6% pill prepared, OK
7. 100 B NaCl spacer injected with considerable resistance
8. 25 B pill injected, resistance
9. Shut in for 24 hrs.
10. Flow at 4000 BPD for 48 hrs.
11. Flow at 15,000 BPD
12. New pill planned


INHIBITOR SQUEEZE
Gladys McCall No. 1
May 1985
Phosphonate
Pill
Salinity
Formation
Brine
Phosphonate (mg/l)
Flow (barrels)
0
50
100
150
500
1000
1500

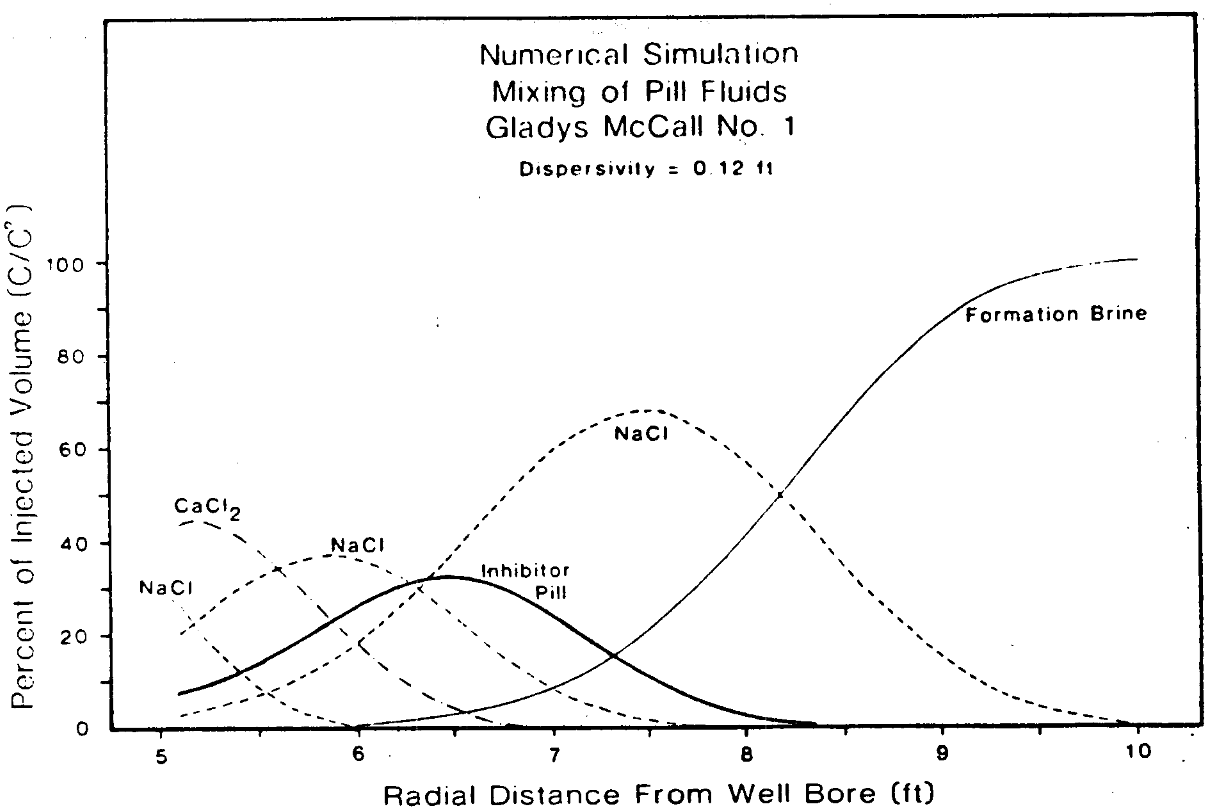
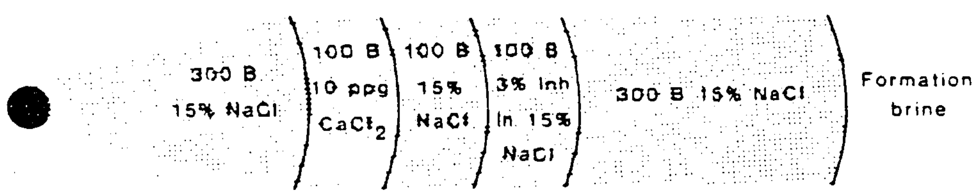
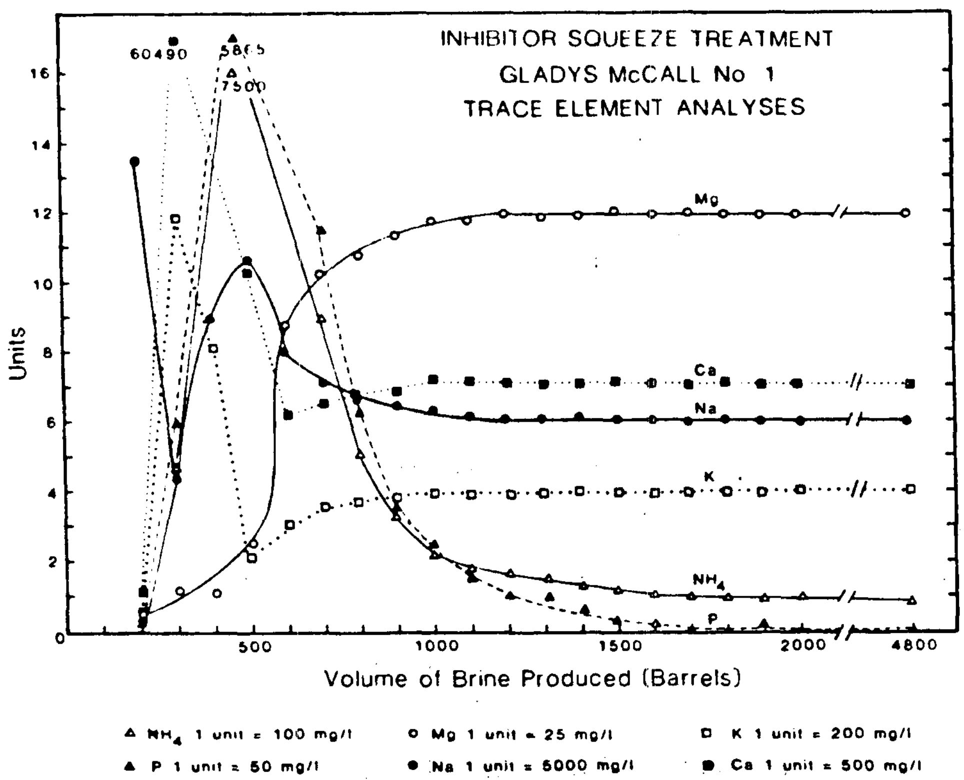


Figure 11. Results of numerical simulation of mixing of pill fluids in Gladys McCall No. 1 formation. Method used is from Gelhar and Collins (1971). Using dispersivity = 0.12 ft.

3. Conclusions

1. Mixing front size deduced
2. Clean brine enters formation with little resistance
3. FeO_x and Ca-Inh precipitation were sources of problems
4. Inhibitor vs. flow results
5. New attempt :

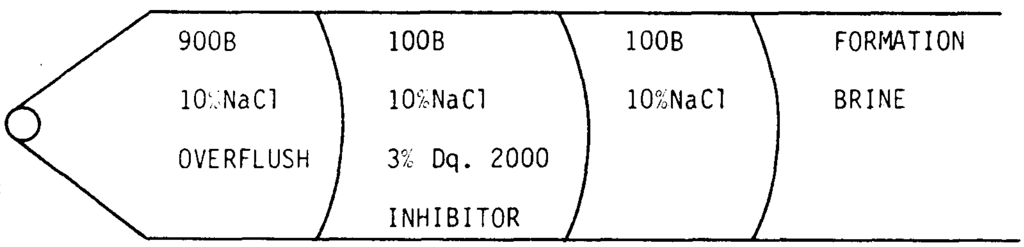




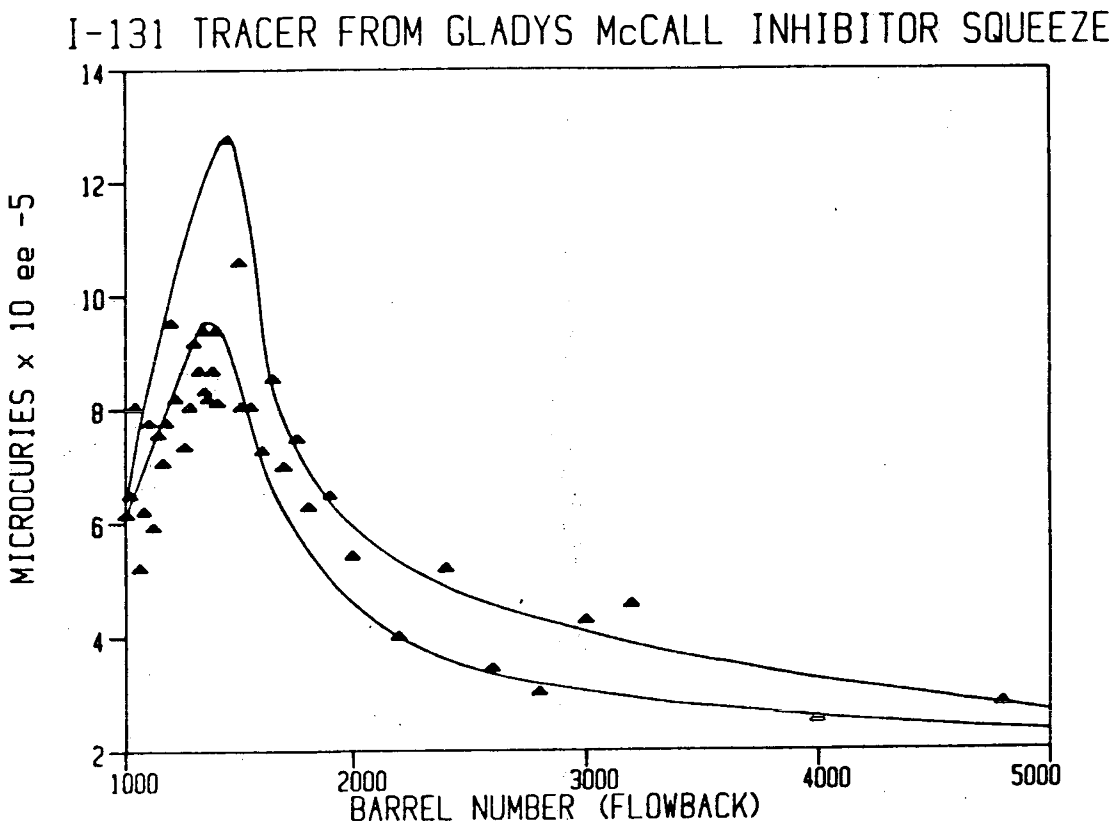
Trace element concentrations, inhibitor squeeze treatment, Gladys McCall No. 1 well. NH_4 and P track inhibitor: 60% returned by 1,000 barrels out. Mg tracks percent of formation brine; dominates by 1,000 barresl out. Ca peak traces CaCla overlfush. K peak may indicate ion exchange for Ca on clays in formation. Na traces NaCl spacers relative to formation brine.

SECOND INHIBITOR SQUEEZE AT GLADYS MCCALL WELL, JANUARY, 1986

DUE TO MODELING, TESTING, INDUSTRY EXPERIENCE, ETC., IT WAS DEEMED POSSIBLE TO SIMPLIFY THE OVERALL SQUEEZE JOB BY ELIMINATING THE $CaCl_2$ OVERFLUSH AND RELYING UPON THE FORMATION CALCIUM FOR MIXING.



PILL WAS PUMPED AWAY AT 4 TO 6 BPMinute.



Plot of Concentration of I-131 (microcuries x 10^{-5}) vs number of barrels for flowback after inhibitor squeeze at Gladys McCall well.

Samples were measured after approximately 8 half-lives of decay. Integration of area under curves yielded nearly quantitative mass balance of total iodine. Detailed modeling is yet to be done; the smooth curves are visual approximation.

HITCHCOCK FIELD WORK

ANALYSIS OF DELEE NO. 1 SAMPLES

Parameter	Lab	Kit
(Concentrations in mg/l unless otherwise noted)		
BRINE		
Alkalinity (as HCO_3)	1312	1050
Bicarbonate (as HCO_3)	552	
Acetic Acids (as HAc)	750	
Calcium	540	630*
Chloride	28000	23000
Hardness (as Ca)	620*	
Sulfate	13	
Total Dissolved Solids	45600	
Total Suspended Solids	100	
pH at 10% CO_2 and 25°C	6.20	
SI Bottom Hole	+0.02	
GAS		
Carbon Dioxide (%)	0.50	

*Calcium test in kit actually measures all divalent cations, so is equivalent to Hardness as Ca.

CARBOXYLIC ACIDS IN DELEE NO. 1 BRINE

CARBOXYLIC ACID	CONCENTRATION (mg/l)
Acetic	705
Propionic	55
Isobutyric	~5
n-Butyric	~5
2-methylbutyric	trace
3-methylbutyric	trace
n-valeric	trace
Total Acids	~770

TRACE METALS IN DELEE NO. 1 BRINE

Element	Concentration (mg/l)
Aluminum	<0.5
Arsenic	<0.1
Barium	6.3
Beryllium	<0.006
Boron	5.0
Cadmium	<0.14
Calcium	547
Chromium	<0.05
Cobalt	<0.3
Copper	0.06
Iron	3.5
Lead	0.14
Magnesium	131
Manganese	0.33
Molybdenum	0.14
Nickel	<0.05
Phosphorous	4.4
Potassium	24
Silicon	110
Sodium	16800
Tin	6.2
Titanium	<0.04
Vanadium	<0.04
Zinc	<0.2
Zirconium	<0.3

BRINE ANALYSES USING KIT
PRETS NO. 1 AND THOMPSON WELLS

	PRETS NO. 1		THOMPSON	
Date	Alkalinity mg/l	Calcium mg/l	Alkalinity mg/l	Calcium mg/l
5/13/85	975	600	1075	635
5/14/85	960	600	1075	635
5/15/85	975	600	1100	635
5/20/85	925	600	1075	600
5/22/85	975	600	1100	600
5/24/85	1000	600	1050	610
5/30/85	1050	610	1000	600

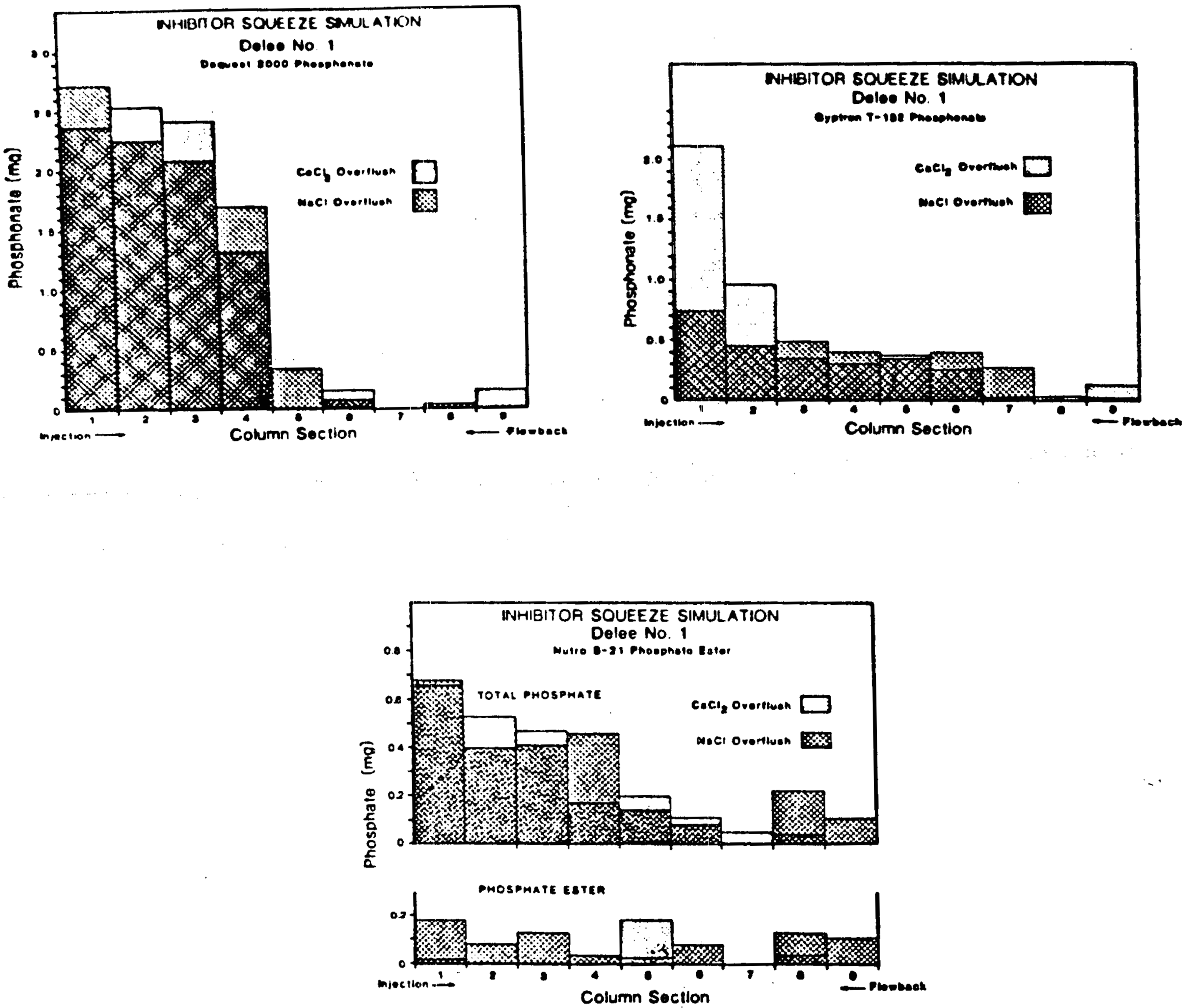
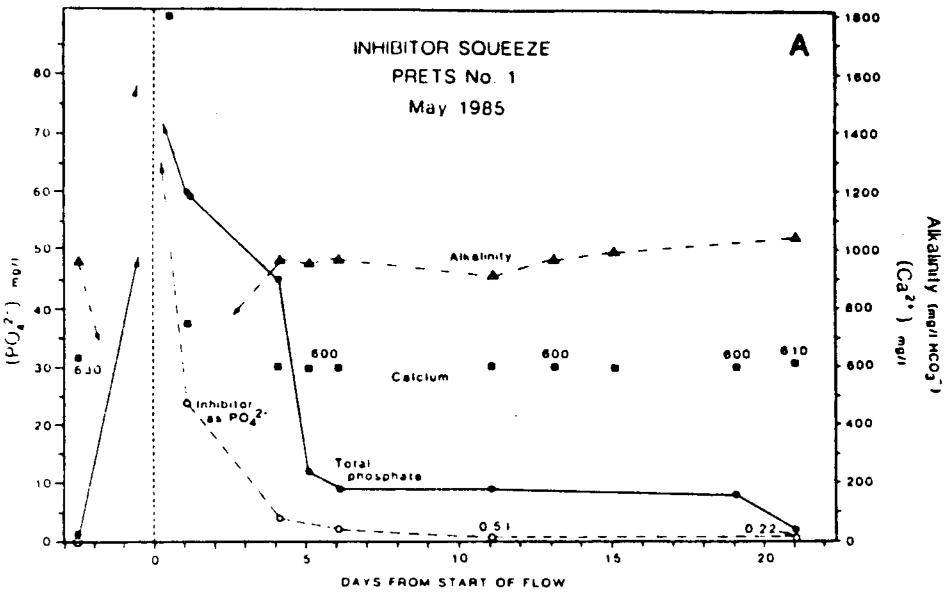


Figure 10. Inhibitor squeeze simulations in rock from Delee No. 1 well. Represents amount of inhibitor retained in each section of the rock column following injection of the "pill" and flowback with brine. (a) Using Dequest 2000 phosphonate, acidic form ofATMP; (b) using Gyptron T-132 phosphonate, neutral form of ATMP; (c) using Nutro S-21 phosphate ester, showing both phosphate ester and total phosphate results. Although there appears to be no advantage to using a $CaCl_2$ overflush, the use of an acidic inhibitor (a) results in increased retention of inhibitor in the rock, which may provide a more effective treatment.



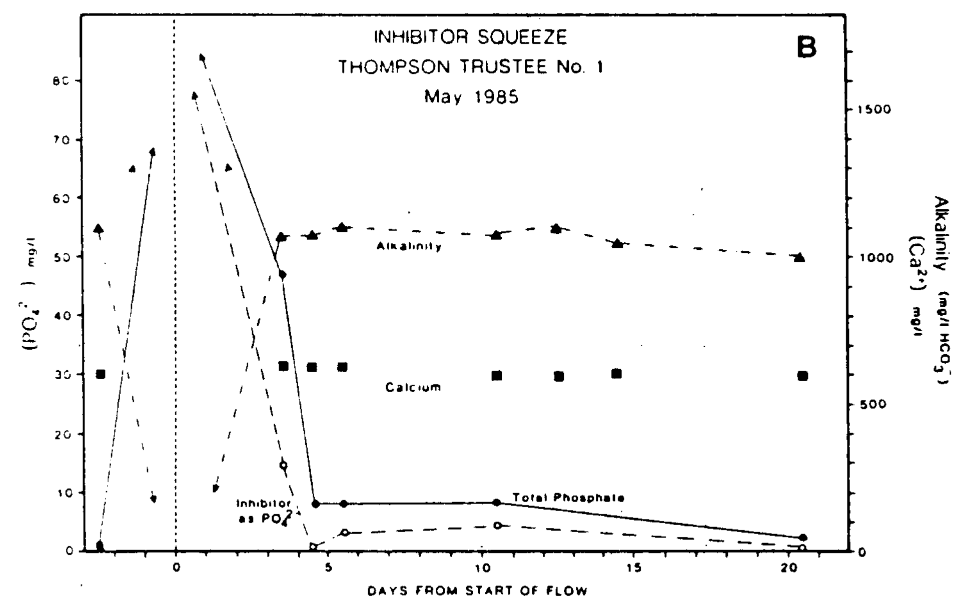
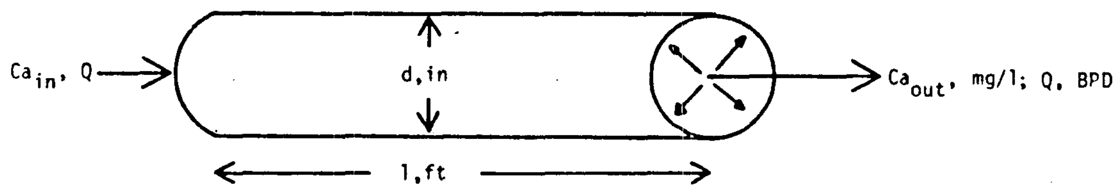


Figure 12. Effect of inhibitor squeeze on brine chemistry at two Hitchcock Field wells. A = Prets No. 1; B = Thompson Trustee No. 1. Samples were taken the day before the wells were cleaned with acid, squeezed with a Phosphate Ester inhibitor (Nutro S-21), and shut in for about two days. Most of the inhibitor appears to have decomposed to orthophosphate.

ESTIMATION OF $CaCO_3$ SCALE RATE AND ACID COST FOR PRETS AND GLADYS WELLS



$J = Q(Ca_{in} - Ca_{out})/A$

$Ca_{out} = Ca_{in} \exp(-Ak_m/Q)$

$J = k_m Ca$

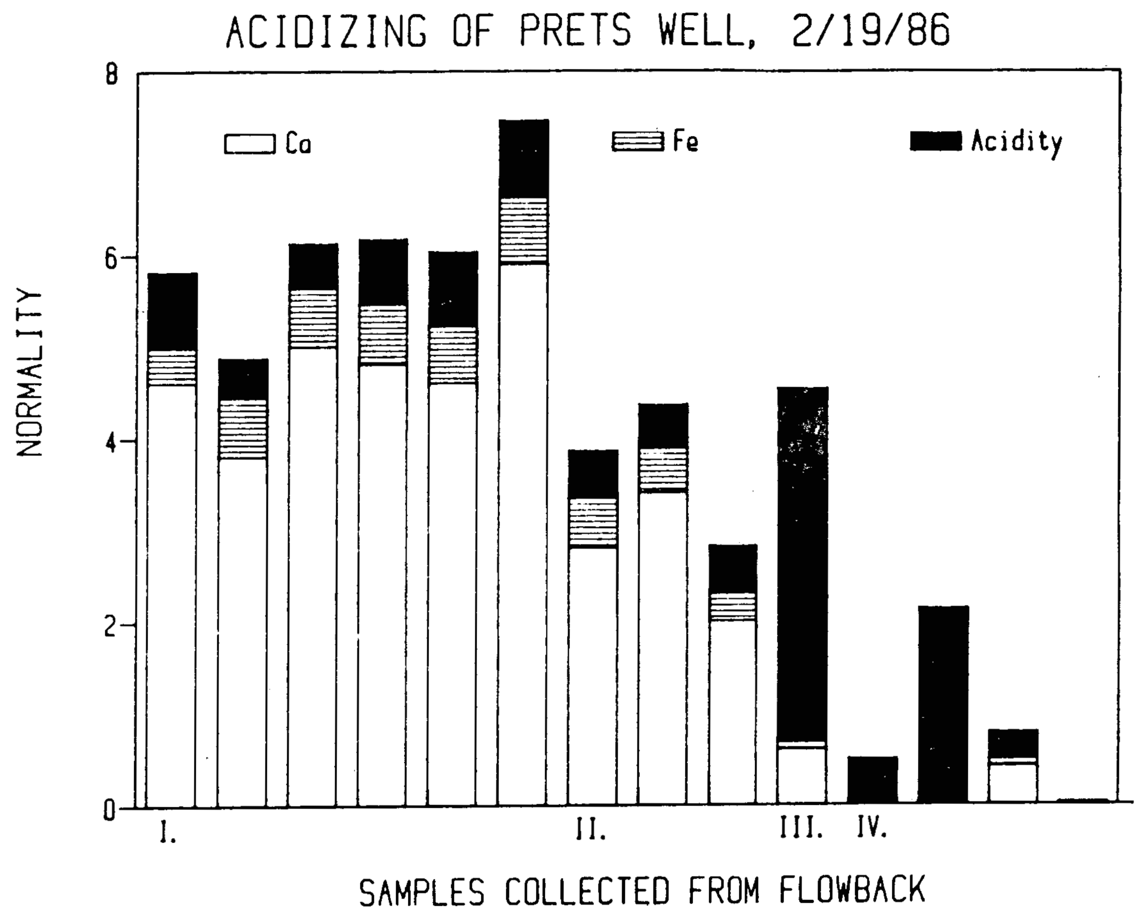
J, g-$CaCO_3$/in^2·day $= 6.21 \times 10^{-4}(Q/l)^{1/3} Ca/d$

$\dot{r}$, in-$CaCO_3$/day $= 1.40 \times 10^{-5}(Q/l)^{1/3} Ca/d$

$\dot{m}$, lb-$CaCO_3$/day $= 5.15 \times 10^{-5}(Q/l^2)^{1/3} Ca$

Cost, \$/day $= 0.83\ \dot{m}$

EXAMPLES		
PARAMETER	PRETS	GLADYS
Q, BPD	5,000	30,000
l, ft	1,000	1,000
Ca, mg/l	700	4,000
d, in	2.5	5.25
J, g-$CaCO_3$/in^2·day	0.30	1.47
$\dot{r}$, in-$CaCO_3$/day	0.0067	0.033
$\dot{m}$, lb-$CaCO_3$/day	62	541
Cost, \$/day	51	631
\$/yr	18,750	194,000

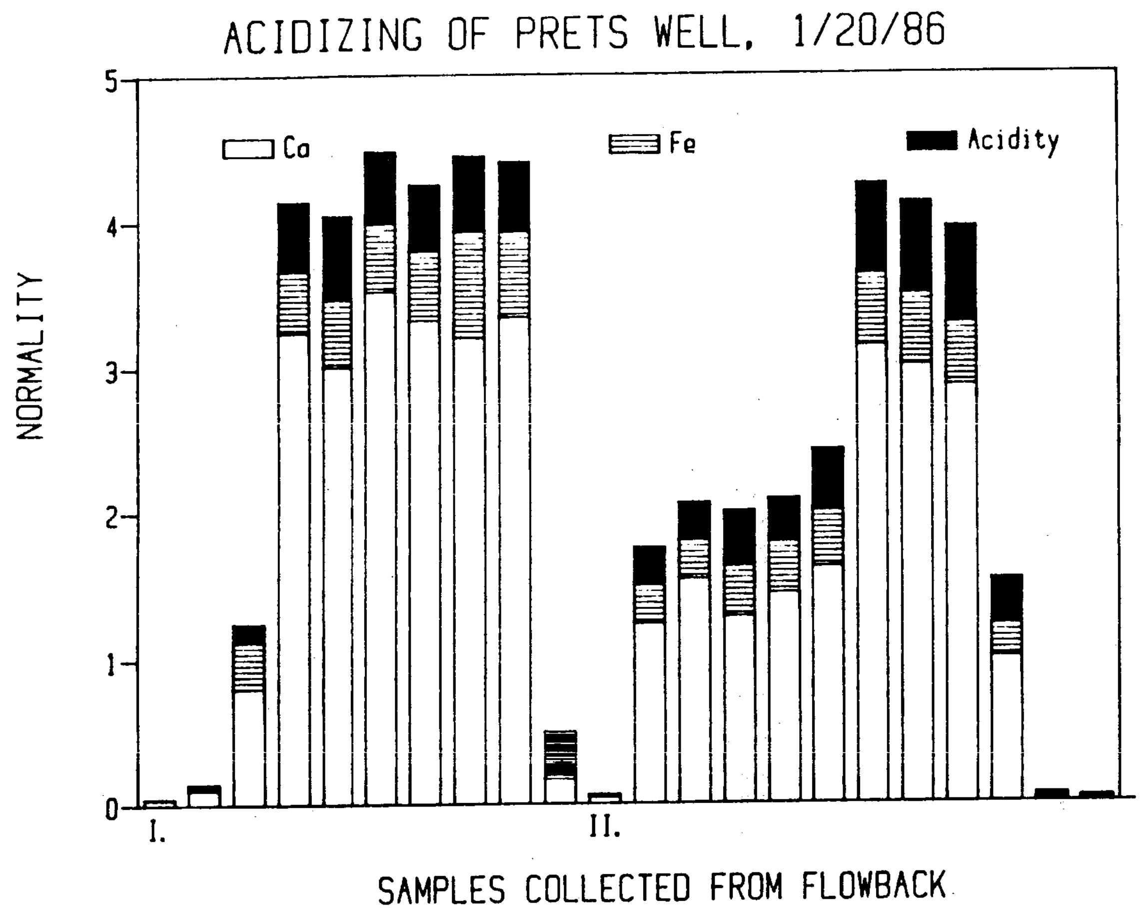


I. 125 gal. of HCl (7.2 N) was pumped into the well to a depth of 500 ft. and shut in for 30 minutes. Samples 1-6 were collected during flowback.

II. 125 gal. of HCl (5.86 N) and A-Sol were pumped to a depth of 500 ft. and shut in for 30 minutes. Samples 7-9 were collected during flowback.

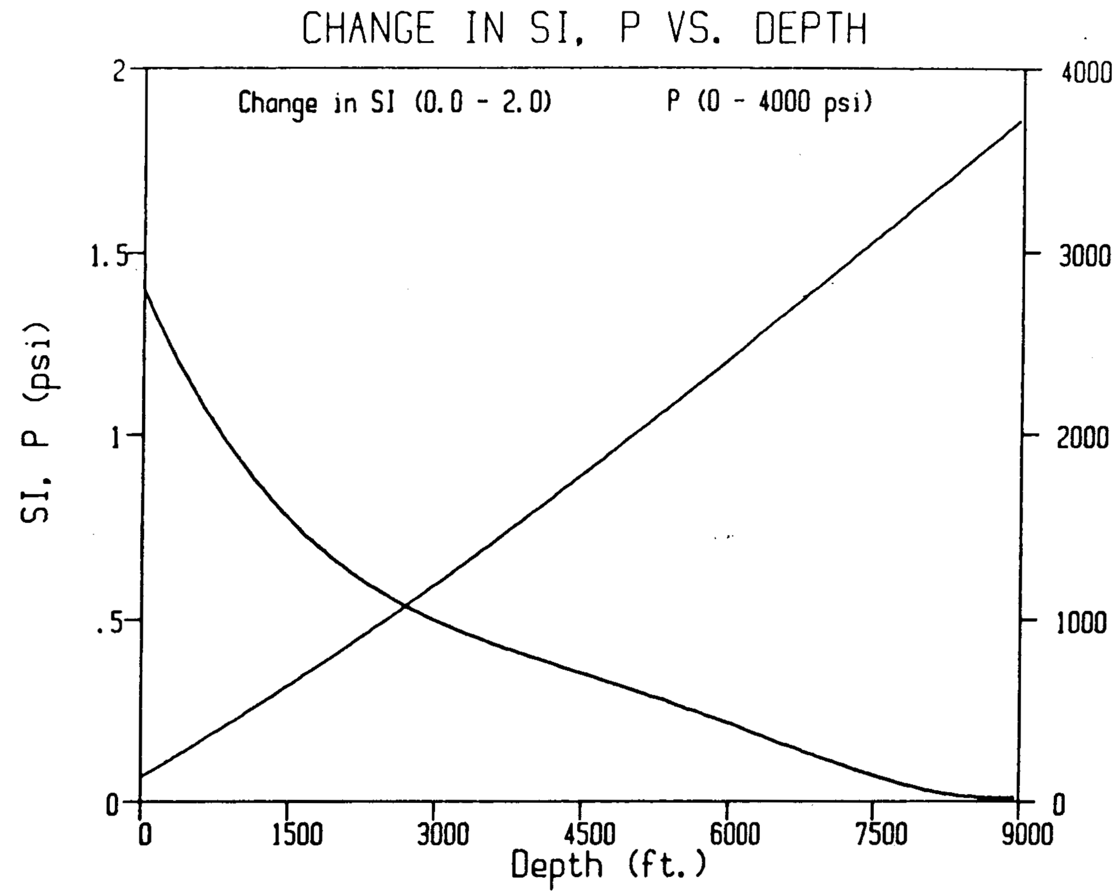
III. 125 gal. of HCl and A-Sol were pumped to a depth of 500 ft. and shut in for 20 minutes. About 60 gal. of unspent acid flowed out of the well. Sample 10 was collected from the flowback.

IV. 60 gal. of unspent acid remaining in the well were pushed back down with 125 gal. of brine to a depth of approximately 750 ft. The well was shut in for 15 minutes. Samples 11-13 were collected during flowback.

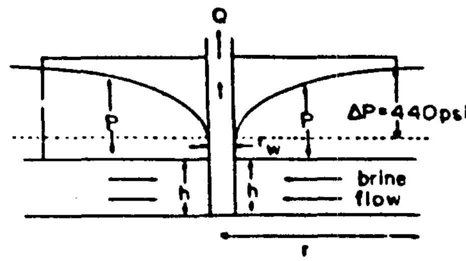


I. 125 gal. of HCl (4.7 N) was pumped into the well, followed by 190 gal. of brine. This pushed the acid to a depth of approximately 1200 ft. The well was shut in for 30 minutes. Samples 1-11 were collected during flowback.

II. 125 gal. of HCl followed by 380 gal. of brine and spent acid were pumped into the well. This pushed the acid to a depth of approximately 2000 ft. The well was shut in for 30 minutes. Samples 12-22 were collected during flowback.



PLOT OF THE CALCULATED CHANGE IN SATURATION INDEX AND PRESSURE VERSUS DEPTH FOR THE PRETS WELL. A CRITICAL SI IS PROBABLY NEAR 1.0 TO 1.2 OR AT ABOUT 500 FT DEPTH.



STEADY STATE RADIAL FLOW:

(1) $$P - P_w = \frac{Q(BPD)}{200} \ln \frac{r}{r_w}$$ (L. ANDERSON)

FROM SI EQUATION AND ASSUMMING CONTINUOUS EQUILIBRIUM OF $CaCO_3$ IN THE FORMATION:

(2) $$\left| \frac{T\text{-}Ca \cdot ALK^2}{P} \right|_{r_1} = \left| \frac{T\text{-}Ca \cdot ALK^2}{P} \right|_{r_2}$$

BY SUBSTITUTING EQUATION 2 INTO EQUATION 1 ALONG WITH CONSIDERABLE ALGEBRAIC MANIPULATION THE FRACTIONAL LOSS IN POROSITY AT r, Δn_r, CAN BE SHOWN TO BE:

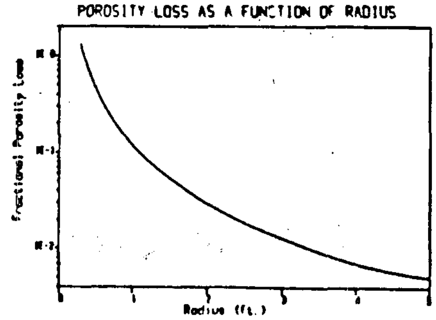
$$\Delta n_r = \frac{1.11 \times 10^{-6}}{2 \pi n h r^2} V_{total}$$

WHERE n IS POROSITY, h IS FORMATION THICKNESS IN dm (3.05 dm = 1.00 ft), r IS RADIUS IN dm, AND V_{total} IS TOTAL VOLUME IN dm^3 (158 dm^3 = 1 B).

FOR n = 0.3, h = 100 ft, V_{total} = 10^4 BPD FOR 1 YEAR:

$$\Delta n_r = \frac{0.119}{r^2} \quad r \text{ in ft}$$

POROSITY LOSS AS A FUNCTION OF RADIUS



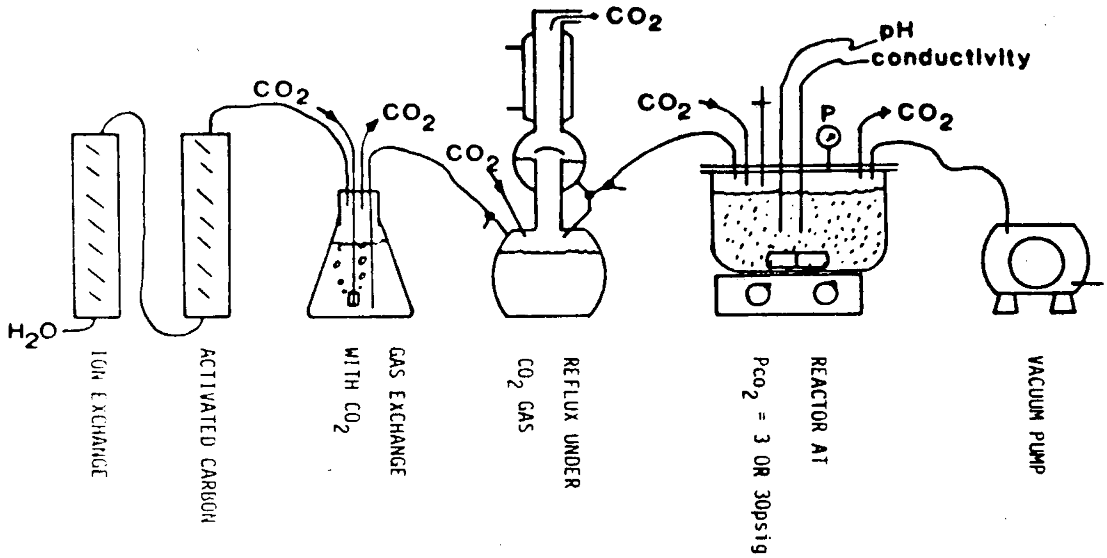
COMPARISON OF PRETS AND PORT ARTHUR BRINES

	PRETS	PORT ARTHUR*
ALKALINITY (mgHCO_3/l)	720	366
HARDNESS (mgCa/l)	588	762
pH AT ATMOSPHERIC P.	6.8	6.5
FRACTION CO_2 IN GAS	0.050	0.038
CONDUCTIVITY (μmhos/cm)	67500	76540
TDS (mg/l calculated)	39000	67000
Temperature (°F) B.H.	210	234
Pressure (psi) B.H.	4100	8827

*THESE SAMPLES CONTAINED SIGNIFICANT QUANTITIES OF HEMATITE, Fe_2O_3, AS WEIGHT, BUT THIS MAY HAVE MINIMAL EFFECT ON THE REPORTED PARAMETERS.

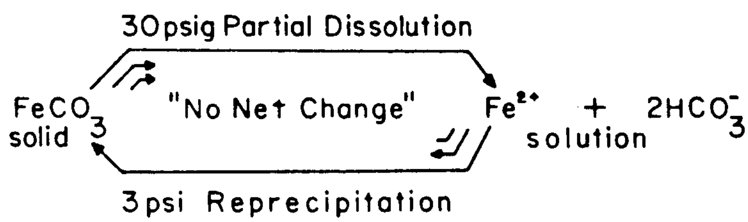
LABORATORY EXPERIMENTS

$FeCO_3$ PRECIPITATION AND DISSOLUTION KINETICS AND EQUILIBRIA vs. T



ABILITY TO PREPARE AND HANDLE VIGOROUSLY ANOXIC WATERS AND REACTION SYSTEMS.

DISCOVERED A NEW METHOD TO MEASURE PRECIPITATION KINETICS BY SIMPLY MEASURING WATER LOSS RATE AT STEADY STATE. ADVANTAGE IS EASE WITH WHICH ACCURATE KINETICS CAN BE MEASURED.



$K_{sp}^{FeCO_3}$ - 25°C, 40°C, 60°C

DISSOLUTION RATE LAW AND CONSTANTS 25°C, 40°C, 60°C.

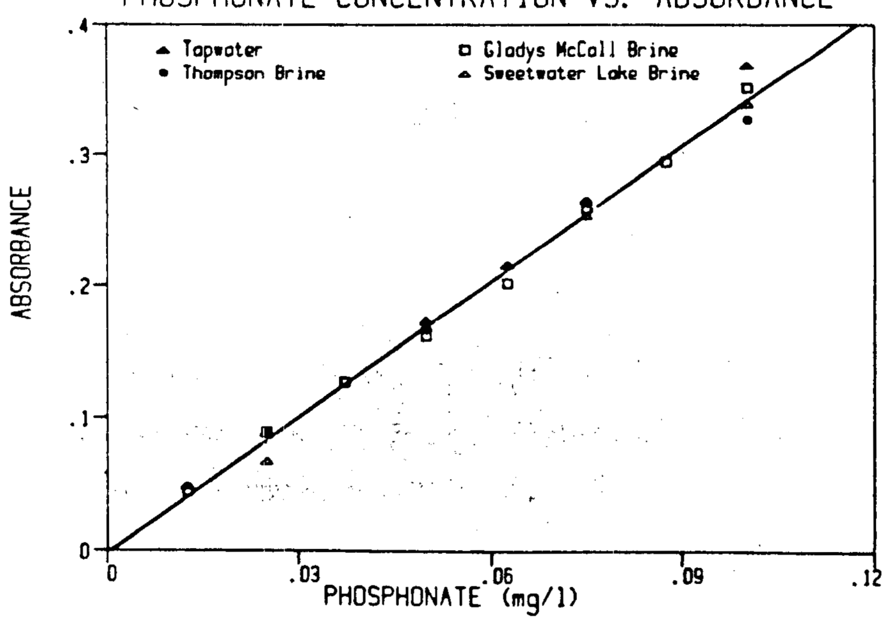
PRECIPITATION RATE LAW AND CONSTANTS 25°C, 60°C.

ANALYTICAL METHOD FOR LOW CONCENTRATIONS OF PHOSPHONATE IN BRINE

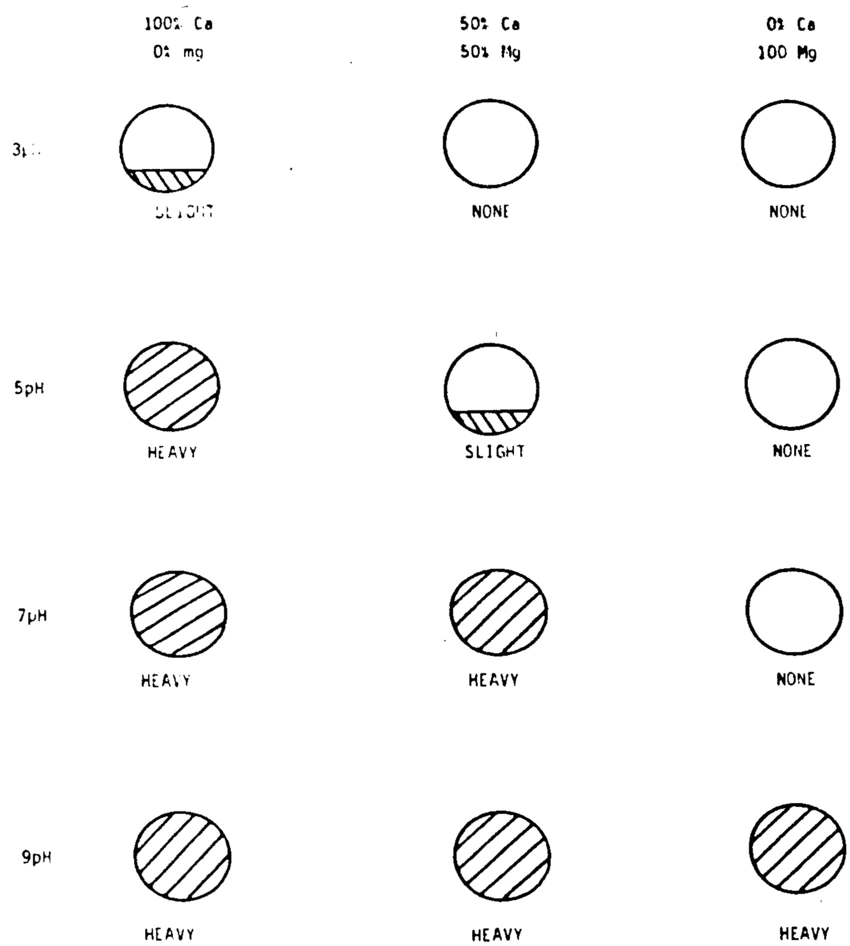
SUMMARY OF PROCEDURE:

$H_2O_3P-\overset{\vert}{\underset{\vert}{C}}-$	PHOSPHONATE INHIBITORS
$\downarrow$ UV/PERSULFATE	$\downarrow$ OXIDIZED
H_2O_3POH	PHOSPHATE
$\downarrow$ MoO_3	$\downarrow$ MOLYBDATE
$Mo_{12}O_{39}P$	NEUTRAL MOLYBDATE/PHOSPHATE COMPLEX
$\downarrow$ iso-C_4H_9OH	$\downarrow$ ISOBUTYL ALCOHOL EXTRACT
$Mo_{12}O_{39}P$/iso-bu-OH	NEUTRAL CLEAR COMPLEX IS EXTRACTED INTO
	iso-bu-OH LEAVING MOST INTERFERENCES IN THE WATER.
$\downarrow$ $SnCl_2$	$\downarrow$ REDUCING AGENT
$Mo_{12}O_{38}P$/iso-bu-OH	MEASURED AT 725 nm.
INTENSE BLUE COLOR	

PHOSPHONATE CONCENTRATION VS. ABSORBANCE



EXTENT OF PRECIPITATION FROM 1% PHOSPHONATE (Dq. 2000)



QUALITATIVE DEPICTION OF THE EFFECT OF Mg/Ca/pH ON PRECIPITATION OF DEQUEST 2000 PHOSPHONATE INHIBITOR. TWELVE 250 ml BREAKERS CONTAINING pH ADJUSTED 2 M NaCl AND 1% DQ. 2000 WERE PREPARED. TO EACH WAS ADDED 0.8 M Ca^{2+} OR MIXTURE. THE MIXTURES WERE STIRRED AND THEN ALLOWED TO STAND AND PRECIPITATION WAS NOTED.

SUMMARY OF PROGRESS TO DATE

A. Scale in surface equipment at several wells has been economically controlled with generic inhibitors.

B. An algorithm with appropriate nomographs to predict the specific effects of various production parameters on scale formation has been developed and calibrated with data from several wells.

C. An easily used kit to measure chemical parameters needed for scale control has been completed and is available for operator use.

D. In the laboratory:

1. An apparatus to simulate the high T, P, TDS and flow conditions of wells has been built and is routinely used to screen inhibitors, etc.;

2. Numerous backup procedures, such as for measurement of carboxylic acids, hydrocarbons, trace metals, viscosity, etc., used to characterize brine chemistry more fully have been tested and are routinely used.

3. An analytical procedure to measure phosphonate concentrations in brine below 0.1 mg/l has been developed and applied to several brines.

E. The first quantitative theory of inhibitor action for calcite scale control has been developed and tested with over twenty generic inhibitors and inhibitor blends. Two prime consequences are first that an "inordinately" effective inhibitor does not and will not exist, and second the effect of inhibitors in various blends should be strictly additive and not synergistic.

F. Two inhibitor squeezes have been designed and successfully tested in the field for formations which contain no calcite cement. This has enabled doubling of production from 15 to 30 thousand barrels per day without scale. This first squeeze lasted <u>at least</u> 6 months. The second is still working at 3 months.

G. Several acidizing jobs on the Prets Well have been evaluated and procedures recommended in order to test the efficiency of the hydrochloric acid use. In conjunction, a purely mathematical prediction of scale formation rate has been developed using only bulk flow parameters and seems to correlate well with observed scale formation rates.

FUTURE WORK AND DISCUSSION

PROPOSED WORK

I. CONTINUE OUR PRESENT LEVEL OF ASSISTANCE:

A. FIELD ANALYSES OF CHEMICAL PARAMETERS AND INTERPRETATION OF DATA.

B. ANALYTICAL WORK IN LABORATORY, INCLUDING INHIBITOR EVALUATION.

C. INFORMATION TRANSFER

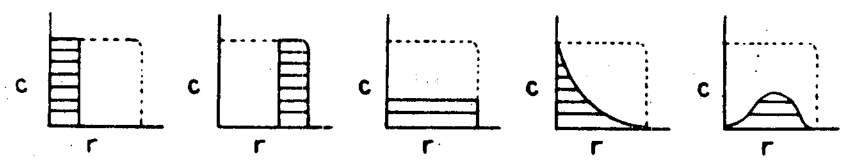
1. AS INDIVIDUALLY REQUESTED.

2. VIA PUBLICATIONS

II. FATE OF INHIBITORS IN FORMATIONS. WHAT ARE THE LIMITS OF AN INHIBITOR SQUEEZE?

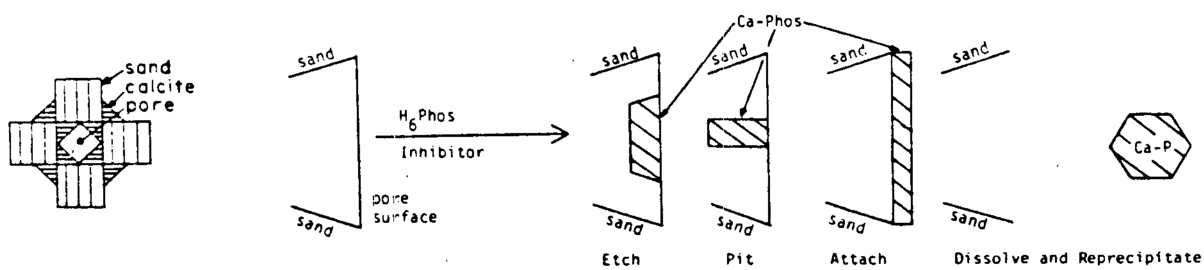
NOTE: 500 lb OF INHIBITOR AT $2/lb COULD CONTROL SCALE IN 5000 BPD BRINE WITH 0.25 mg/l FOR 2 YEARS.

A. OPERATIONALLY:



Inh. conc vs. distance

B. MECHANISTICALLY:



C. RELEASE CONTROL:

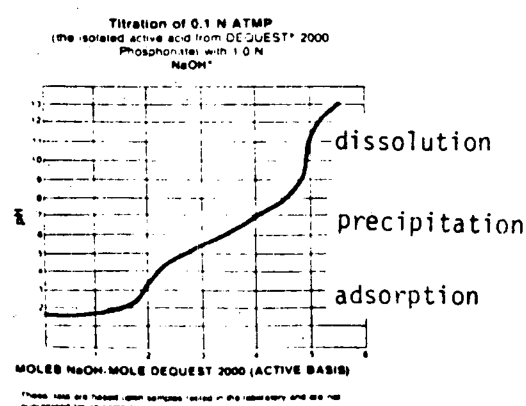
IS THE SLOW RELEASE OF INHIBITORS CONTROLLED BY THE SOLID PHASE WHICH FORMS OR BY THE SOLUTION PHASE COMPOSITION?

D. MIXED OVERFLUSH:

1. Ca/Mg/pH INTERACTION

2. FORMATION TYPE

3. MIXED INHIBITORS



III. ANALYTICAL METHODS:

ANALYTICAL METHODS ARE AVAILABLE FOR MEASURING THE CONCENTRATION OF ALL "NORMAL" COMPONENTS OF BRINE; INCLUDING ALL SOLUTION, GAS, AND SOLID PHASE COMPONENTS. WORK IS NEEDED ON THE SEPARATION AND MEASUREMENT OF TRACE CONCENTRATIONS OF INHIBITOR MIXTURES AND OF CARBOXYLIC ACID INHIBITORS. THIS WILL MOST LIKELY BE DONE BY HIGH PRESSURE LIQUID CHROMATOGRAPHY.

IV. RELATIONSHIP OF SCALE TO CORROSION. A FILM OF SCALE IS GENERALLY PROPOSED TO BE RESPONSIBLE FOR CORROSION INHIBITION IN SCALE FORMING BRINES AND WATERS. IF SCALE IS "ABSOLUTELY" INHIBITED, IT MAY PROMOTE CO_2-ATTACK CORROSION.